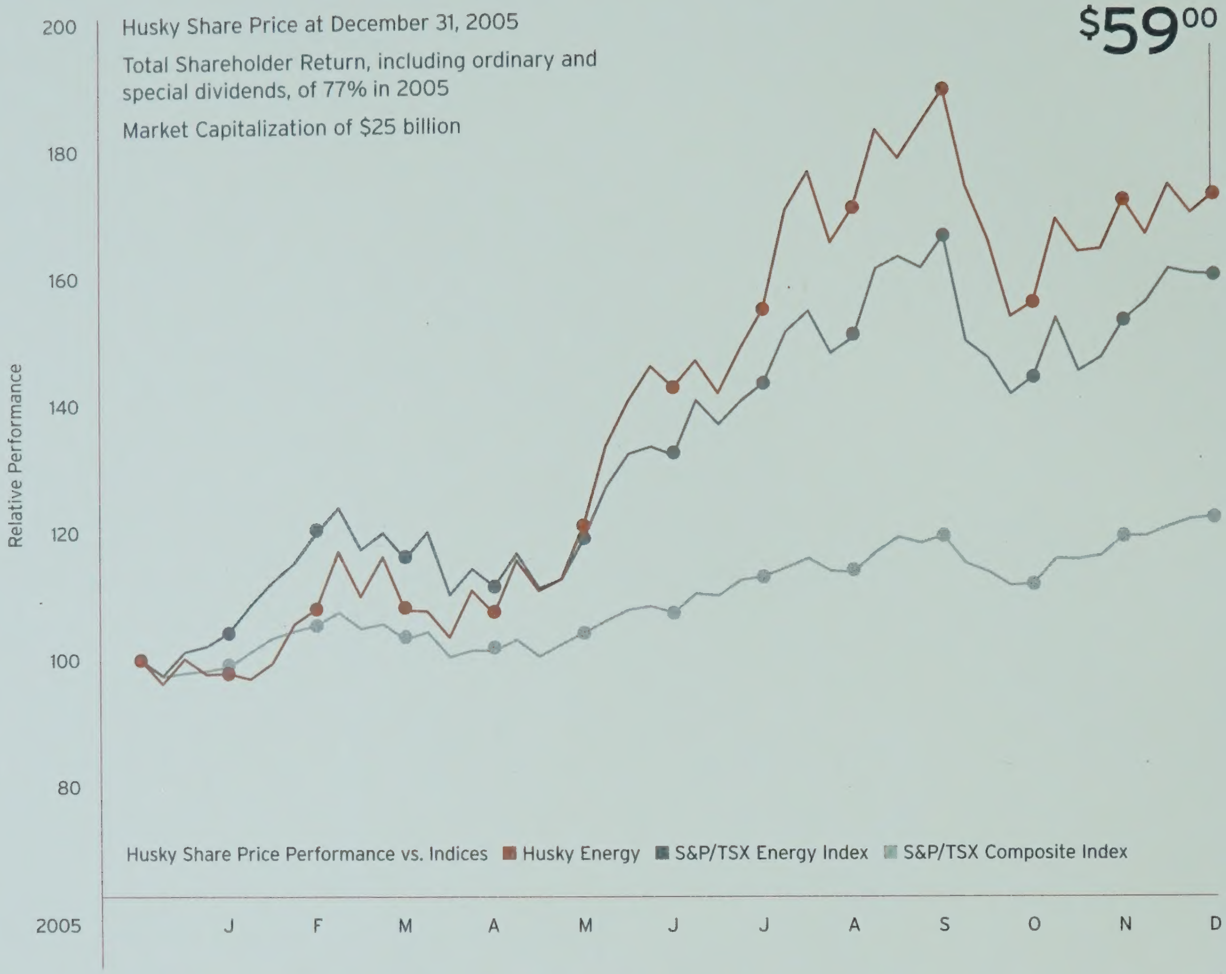
Husky Energy Inc.

Annual Report to the Shareholders

2005



HSE

Husky Energy Inc.

Corporate Profile

Husky Energy Inc. is a Canadian integrated energy and energy-related company with operations in upstream, midstream and refined products.

Upstream includes the exploration, development and production of crude oil, bitumen and natural gas in Western Canada, offshore the Canadian East Coast, in the South and East China Seas, offshore Indonesia and other international areas.

Our midstream operations include the upgrading of heavy crude oil into premium synthetic crude oil, pipeline transportation, gas storage, cogeneration, and the marketing of crude oil, natural gas, natural gas liquids, sulphur and petroleum coke.

Refined products comprises the refining, marketing and distribution of gasoline, diesel, asphalt, ethanol, and ancillary services in Canada and the United States, and a network of retail outlets from Ontario to British Columbia and the Yukon.

Husky Energy Inc. is headquartered in Calgary, Alberta, Canada, and is listed on the Toronto Stock Exchange under the symbol HSE.

MISSION

To maximize returns to our shareholders in a socially responsible manner.

VISION

To create superior shareholder value through financial discipline and a quality asset base.

Table of Contents

Husky at a Glance

Western Canada

Business
- Crude oil and natural gas exploration, development and production

Strategy
- Increase oil and gas production through exploitation and exploration
- Focus on natural gas exploration in the deeper portion of the Western Canada Sedimentary Basin and natural gas from coal and tight sands in the plains region

2005 Plans
- Grow Western Canada conventional oil and gas production by 4%
- Achieve production replacement reserves of greater than 100%
- Pursue unconventional gas plays and participate in the drilling of 300 natural gas from coal wells

2005 Achievements
- Achieved production replacement ratio of 96% before acquisitions and divestitures
- Produced 10 mmcf/day of natural gas from coal and drilled 300 wells
- Significant discovery made at Summit Creek, N.W.T.

2006 Plans
- Maintain Western Canada conventional oil and gas production
- Achieve 100% production replacement ratio
- Produce 35 mmcf/day of natural gas from coal
- Drill two wells in N.W.T.

Heavy Oil

Business
- Heavy oil production in the Lloydminster area of Alberta and Saskatchewan

Strategy
- Optimize and expand heavy oil operations

2005 Plans
- Grow heavy oil production by 10%
- Reduce operating costs by $26 million

2005 Achievements
- Drilled 507 total wells (heavy, medium and gas)
- Operating cost initiatives realized savings of $34 million
- Achieved reserve replacement of 95% of production

2006 Plans
- Expand heavy oil production by 10%
- Achieve reserve replacement of 100% of production
- Reduce operating costs by $35 million
- Initiate cold enhanced oil recovery pilot

Oil Sands

Business
- 100% ownership of leases in the Cold Lake and Athabasca oil sands

Strategy
- Develop in-situ bitumen resources commencing with Tucker and then Sunrise oil sands leases

2005 Plans
- Commence drilling and facility construction for Tucker Oil Sands Project
- Obtain regulatory approval and progress with front-end engineering for Sunrise Oil Sands Project

2005 Achievements
- Drilling and construction for Tucker on-schedule and on-budget
- Regulatory approval obtained for Sunrise
- Conceptual studies completed for Sunrise

2006 Plans
- First oil by end of year at Tucker
- Progress front-end engineering design for Sunrise upstream facilities and select upgrading solution
- Drill resource evaluation wells at Sunrise
- Evaluate Caribou reserves

Canada's East Coast

Business
- 12.51% interest in Terra Nova oil field
- 72.5% interest in, and operator of White Rose oil field
- 1.4 million acres of exploration acreage and a working interest in 15 Significant Discovery Areas

Strategy
- Maximize value of White Rose assets
- Explore White Rose satellite opportunities and evaluate gas potential
- Participate in continuing development of light oil production from Terra Nova

2005 Plans
- Achieve White Rose first oil in late 2005 or early 2006
- Investigate feasibility of developing and transporting gas from White Rose
- Drill exploratory wells in Terra Nova Far East block and in South Whale Basin

2005 Achievements
- First oil from White Rose achieved ahead of schedule and on-budget
- Approximately 2.4 million barrels of oil produced from the White Rose oil field (1.74 million net to Husky)
- Six satellite prospects identified
- Husky's share of Terra Nova production averaged 12,400 bbls/day

2006 Plans
- White Rose peak production of 100,000 bbls/day, 72,500 net to Husky
- Further delineate White Rose West and North pools
- Evaluate new White Rose leads and prospects
- Start production from Terra Nova Far East Flank
- Delineate Terra Nova Far East South reserves

Upstream
Midstream
Refined Products

International

Business
- 40% interest in Wenchang 13-1 and 13-2 producing oil fields in the South China Sea
- 100% interest in six exploration blocks in the South and East China Seas
- 100% working interest in the Madura Block offshore Indonesia

Strategy
- Pursue development opportunities near Wenchang
- Increase resource base through exploration drilling
- Increase production from international business to 10% of total production

2005 Plans
- Additional development drilling in the Wenchang field
- Drill three exploration wells offshore China
- Secure gas sales contract and prepare development plan for Madura BD field, Indonesia

2005 Achievements
- Wenchang averaged 16,000 bbls/day
- Development wells delayed until 2006
- Drilled Wushi oil discovery
- Negotiations commenced for gas sales agreement for Madura BD field

2006 Plans
- Drill four infill development wells at Wenchang
- Evaluate potential Wushi discovery
- Sign gas sales contract for Madura BD field and receive development approval

Midstream

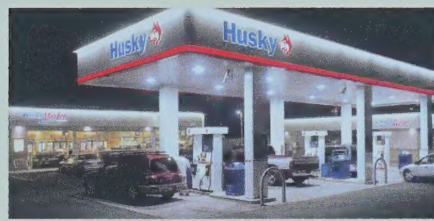
Business
- Upgrading of heavy oil into premium synthetic crude oil
- 2,050-kilometre crude oil pipeline system
- Marketing of crude oil, natural gas, natural gas liquids, sulphur and petroleum coke
- Electrical generation
- Crude oil and natural gas storage

Strategy
- Increase upgrader capacity to meet future heavy oil and bitumen production volumes
- Increase and optimize crude oil pipeline volumes
- Increase value of Husky's assets through growth in the commodity marketing business

2005 Plans
- Upgrader debottlenecking project to be 60% complete by end of 2005
- Expand Husky's transmission pipeline to meet demand
- Expand gas storage business by 20%
- Expand commodity marketing volumes to exceed 950,000 boe/day

2005 Achievements
- Upgrader debottlenecking project 60% complete
- Hardisty terminal shipments exceeded 250,000 bbls/day of Western Canadian Select Blend
- Gas storage capacity increased by 20% net
- Commodity marketing volumes exceeded 950,000 boe/day

2006 Plans
- Complete upgrader debottlenecking project
- Expand third party terminalling
- Expand pipeline to support production growth
- Connect pipeline to Tucker Oil Sands Project
- Expand gas storage business by 25%
- Expand commodity marketing volumes to exceed 1 million barrels of oil equivalent per day



Refined Products

Business
- Retail network of over 500 units
- 10,000-barrel per day refinery at Prince George, B.C.
- 27,000-barrel per day asphalt refinery at Lloydminster, A.B.
- 10-million litre per year ethanol plant at Minnedosa, M.B.

Strategy
- Enhance outlets with improvements, upgrades, ancillary sales and alliances
- Optimize product supply agreements
- Grow asphalt sales through higher margin premium quality products and new markets
- Become Western Canada's largest ethanol producer

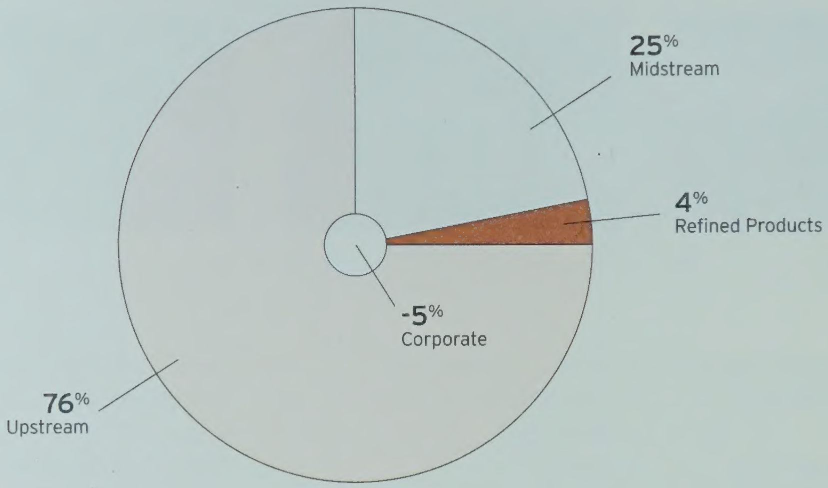
2005 Plans
- Increase fuel volume throughput by 3% over 2004
- Increase ancillary margin by 4% over 2004
- Complete gasoline portion of Prince George Refinery Clean Fuels Project
- Complete study to expand Minnedosa Ethanol Plant to 130 million litres per year
- Construct 130-million litre per year ethanol plant at Lloydminster, S.K.

2005 Achievements
- Fuel volume throughput per location increased 9%
- Ancillary margin increased by 13%
- Gasoline at Prince George Refinery meets new Federal Government regulations on sulphur
- Lloydminster refinery capacity increased to 27,000 from 25,000 bbls/day
- Minnedosa expansion construction initiated
- Lloydminster Ethanol Plant 50% completed

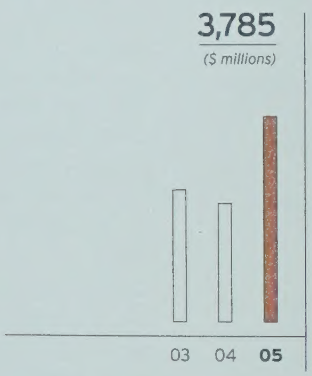
2006 Plans
- Increase fuel volume throughput per location by 3.5% over 2005
- Increase ancillary income by 2.5% over 2005
- Increase Prince George Refinery throughput to 12,000 bbls/day
- Commission ultra-low-sulphur diesel production unit at Prince George Refinery
- Complete construction of Lloydminster Ethanol Plant

2005 Performance

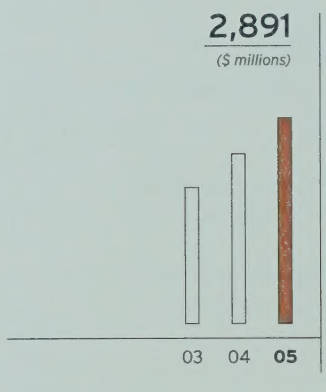
Net Earnings



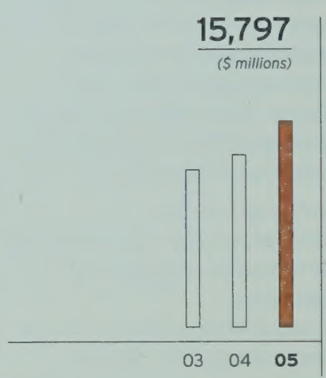
Cash Flow From Operations



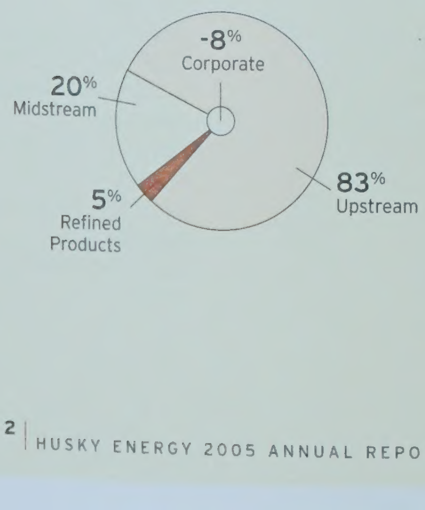
Capital Expenditures



Total Assets



Cash Flow From Operations



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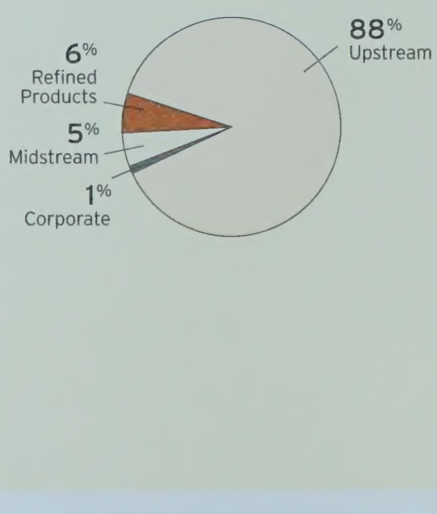

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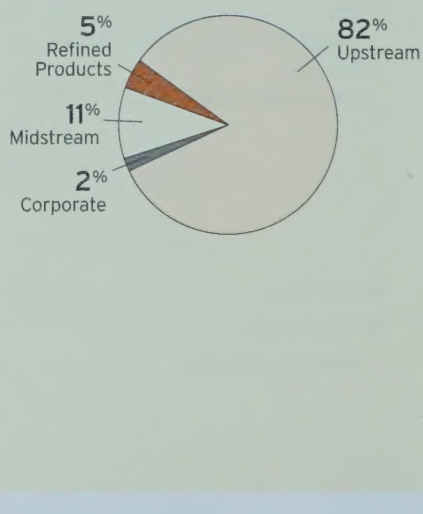


2005 HIGHLIGHTS

Husky's 2005 net earnings doubled to a record $2 billion, mainly due to its strong financial discipline and superior project execution. The Company's White Rose Project was completed ahead of schedule and on-budget. Regulatory approval was also received for the 200,000 barrels per day Sunrise Oil Sands Project.

John C.S. Lau, President & Chief Executive Officer

Year ended December 31	**2005**	2004
(millions of dollars except where indicated)		
Financial		
Sales and operating revenues, net of royalties	**10,245**	8,440
Cash flow from operations	**3,785**	2,197
Per share *(dollars)* – Basic	**8.93**	5.19
– Diluted	**8.93**	5.18
Net earnings	**2,003**	1,006
Per share *(dollars)* – Basic	**4.72**	2.37
– Diluted	**4.72**	2.37
Capital expenditures [(1)]	**2,891**	2,354
Return on average capital employed *(percent)*	**22.8**	13.0
Return on equity *(percent)*	**29.2**	17.0
Debt to capital employed *(percent)*	**20.1**	25.8
Debt to cash flow from operations *(times)*	**0.5**	1.0

(1) Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.

Year ended December 31	**2005**	2004
Operating		
Daily production, before royalties		
Light crude oil & NGL *(mbbls/day)*	**64.6**	66.2
Medium crude oil *(mbbls/day)*	**31.1**	35.0
Heavy crude oil *(mbbls/day)*	**106.0**	108.9
Total crude oil & NGL *(mbbls/day)*	**201.7**	210.1
Natural gas *(mmcf/day)*	**680.0**	689.2
Barrels of oil equivalent *(mboe/day)*	**315.0**	325.0
Proved reserves, before royalties		
Light crude oil & NGL *(mmbbls)*	**273**	238
Medium crude oil *(mmbbls)*	**91**	86
Heavy crude oil [(2)] *(mmbbls)*	**217**	105
Bitumen *(mmbbls)*	**48**	–
Natural gas *(bcf)*	**2,136**	2,169
Barrels of oil equivalent *(mmboe)*	**985**	791
Synthetic crude oil sales *(mbbls/day)*	**57.5**	53.7
Pipeline throughput *(mbbls/day)*	**474.0**	492.0
Light oil sales *(million litres/day)*	**8.9**	8.4
Asphalt product sales *(mbbls/day)*	**22.5**	22.8
Refinery throughput *(mbbls/day)*	**35.2**	35.1

(2) For 2004, includes a negative non-technical revision for year-end heavy oil pricing of 120 mmbbls.

Report to Shareholders

Mr. Victor T. K. Li
Co-Chairman

Mr. Canning K. N. Fok
Co-Chairman

Mr. John C. S. Lau
President &
Chief Executive Officer

We are pleased to report that 2005 has been another record year for Husky Energy. Net earnings and cash flow from operations reached $2 billion and $3.8 billion, respectively. Return on equity exceeded 29 percent. A special dividend of $1 per share was declared in October enabling shareholders to benefit directly from the Company's financial performance. The regular quarterly dividend per share was increased by 79 percent to $0.25.

Husky's financial performance reflected the continuing strength in oil and gas prices with West Texas Intermediate (WTI) averaging U.S. $56.56 per barrel for 2005 compared with U.S. $41.40 for 2004, when the Company's results were affected by crude oil price hedges. Presently, Husky has no oil and gas price hedges in place.

During 2005, capital expenditures, excluding capitalized amounts, rose to $2.9 billion from $2.4 billion in 2004. The increase was primarily due to the early start-up of White Rose and the increasing capital intensity in the Western Canada Sedimentary Basin.

Full year operating costs were $8.12 per barrel of oil equivalent, compared with $7.32 per barrel of oil equivalent in 2004. Costs were affected by increased fuel and power costs, higher trucking, servicing and maintenance rates and weather delays.

The White Rose oil field, located offshore Newfoundland and Labrador, achieved first oil production in November, ahead of schedule and on-budget. Gross field production is expected to reach 100,000 barrels per day of light sweet crude oil in mid-2006. Husky holds a 72.5 percent working interest and is the operator in White Rose. The Company owns a significant number of licences in the Jeanne d'Arc Basin and plans to carry out an exploration and exploitation program to develop and produce additional oil pools and fields in the area utilizing the *SeaRose FPSO* (floating production, storage and offloading) facility. The feasibility of increasing the production capability of the *SeaRose FPSO* to accommodate incremental development opportunities is under evaluation.

In December, regulatory approval was received for the commercial development of the Sunrise Oil Sands lease. The lease is estimated to contain 3.2 billion barrels of recoverable bitumen resources. Engineering work has commenced on the first phase of the project which is aimed at producing over 200,000 barrels per day of bitumen by using established steam-assisted gravity drainage (SAGD) technology. A number of options are being evaluated with respect to the upgrading, transporting and refining of the produced bitumen. Husky's goal is to maximize the value of this substantial resource which has the potential to strengthen the Company's future growth for many decades.

Excellent progress is being made at the first oil sands project at Tucker. The $500 million development is on-schedule to achieve first oil in 2006, adding over 30,000 barrels per day of production at peak. Tucker production will be transported to the heavy oil upgrader at Lloydminster, Saskatchewan for processing into premium synthetic crude.

In the South China Sea, a rig has been secured to drill an exploration well on the deep water 29/26 Block. Drilling will commence in the second quarter of 2006 to test a natural gas prospect.

In Indonesia, negotiations for a gas sales agreement for the offshore Madura BD field are in progress. Once an agreement is reached, our production sharing contract will be extended and then development will be initiated with production targeted for 2008. This will provide a second core producing area for Husky outside of Canada.

Several projects in the midstream and refined products segments reached milestones in 2005. Debottlenecking of the Lloydminster heavy oil upgrader is expected to be completed in 2006. Plans to expand the upgrader's throughput capacity are under active consideration as the Company's production of heavy oil and other suitable feedstock such as Tucker production continues to grow.

In 2005, the low-sulphur gasoline phase of the Clean Fuels Project at the Prince George light oil refinery was completed. The low-sulphur diesel phase is scheduled to be completed in 2006. The clean fuel project will allow production to meet the new environmental requirements for cleaner fuels, as well as increase the total throughput capacity from 10,000 to 12,000 barrels per day.

Husky is constructing two ethanol plants, each with a production capacity of 130 million litres per year. The first plant, adjacent to the heavy oil upgrader in Lloydminster, is more than 50 percent complete. The second which is being constructed on the site of the existing ethanol plant at Minnedosa, Manitoba is scheduled for completion in 2007. The plants will help meet the demand for environmentally friendly fuels as well as create opportunities for the agricultural industry.

We believe that your Company is well-positioned to enter into its next phase of growth. Husky's proven reserves were 985 million barrels of oil equivalent at the end of 2005, an increase of 8 percent compared to the previous year, excluding the 2004 heavy oil revision. White Rose and Tucker accounted for the majority of the increase in proven reserves. Husky's total proven, probable and possible reserves amounted to 5.6 billion barrels of oil equivalent at the end of 2005. This significant resource base provides a strong foundation for continued production growth as the Company continues to execute its exploitation and development strategy.

Husky has good quality assets and a very strong balance sheet with a debt to cash flow from operations ratio of 0.5 to 1 at the end of 2005. For 2006, Husky has a capital expenditure program of $2.85 billion and production forecast of 360,000 to 390,000 barrels of oil equivalent per day.

Husky's achievements in 2005 were made possible by the dedication and commitment of our management team and employees, and the continued support of our shareholders. On behalf of the Board of Directors, we offer our deepest gratitude.

Victor T. K. Li	Canning K. N. Fok	John C. S. Lau
Co-Chairman	*Co-Chairman*	*President & Chief Executive Officer*

February 6, 2006

Questions and Answers

ANSWERS FROM JOHN C. S. LAU, PRESIDENT & CEO

Mr. John C. S. Lau
President &
Chief Executive Officer

Husky's shareholders continue to benefit from the performance of their Company. In April 2005, the quarterly dividend per common share was increased from \$0.12 to \$0.14 and increased again to \$0.25 in October. A special cash dividend of \$1.00 per common share was also approved in October by the Board of Directors. Total return to shareholders including stock price appreciation and special and ordinary dividends exceeded 77 percent for the year. In this section, John C.S. Lau reviews Husky's strategies, achievements and challenges.

Q1

Husky has achieved significant growth since returning to the public market in 2000. How would you describe Husky's strategies?

Husky's strategies are based on a well-defined vision focused on investing our free cash flow into quality assets with growth potential. Husky developed a vision 10 years ago to develop a strategy with short, medium and long-term objectives.

For the short-term, the Company would invest in conventional oil and gas properties and expand our heavy oil operations. To meet our medium-term objectives of acquiring quality assets for future growth, revenues from our conventional oil and gas holdings were invested in developing our White Rose oil field, offshore Canada's East Coast, and in the Alberta oil sands. With White Rose now on-stream and the Tucker Oil Sands Project scheduled to come on-stream by the end of 2006, Husky is focused on developing our Sunrise Project and exploiting our land position off the East Coast for long-term growth. Our vision is to have first oil from our Sunrise holdings by 2010-12. This will position us to achieve our production target of 500,000 barrels of oil equivalent per day.

Our midstream assets, such as our Lloydminster Upgrader, complement our strategy by enhancing the value of our upstream production.

Q2

How have you strengthened the Company's management team to maintain the momentum of the last few years?

Husky has grown over \$20 billion from a market capitalization of \$5 billion when it became a public company in 2000 to over \$25 billion at the end of 2005. To prepare the Company for the challenges of building on this success and expanding our quality asset base, a strong management team is required.

Key to achieving Husky's vision has been our emphasis on financial discipline and building a strong management team. To meet the challenges of going forward and moving the Company into its next phase we have strengthened our management team, and established a separate business unit for our oil sands operations. The Company has focused its operations and strengthened its management in the areas of project execution and management, operations and refining and oil sands development.

These changes are necessary to carry Husky's vision into the future and ensure that our projects are completed on-time and on-budget as well as increase focus on mergers and acquisitions, and other corporate activities.

Q3

Husky hedged a significant portion of its production in 2004. Did the Company hedge in 2005? What are the Company's plans for 2006 in view of the high commodity prices?

Husky considers commodity price hedging a management tool to protect the Company from volatility in its cash flow. Husky's last oil and gas commodity price hedge program ended in December 31, 2004, and the Company has not entered into any further hedges. The Company's strong financial position in 2005 has allowed us to benefit fully from the rising trend in crude oil and natural gas prices.

There are a number of factors which must be considered with regard to the decision to enter into commodity hedges. The protection of the Company's balance sheet is always the most critical factor. This is reviewed with a long-term view of commodity prices and the projects under development.

Q4

During the last three years Husky has declared a special dividend. Will Husky continue to pay special dividends? Can investors expect this policy to continue?

In the past three years, Husky has achieved record financial performance and maintained a strong balance sheet. In view of the high commodity price environment, the Board of Directors considered the strong cash flows in excess of the capital requirements and decided that shareholders should benefit directly from the excess.

The Board of Directors will consider and approve dividends at the appropriate time based on projections of financial performance, the strength of our balance sheet and capital requirements at that time.

Q5

Husky has announced that its production guidance will be approximately 10 percent greater than the 2005 guidance. Considering the 2005 actual production, how does the Company plan to achieve its goal of a 10 percent increase for 2006?

The unseasonably wet weather in Western Canada during most of 2005 impacted our production. With White Rose expected to reach peak production in the first six months of 2006, we have announced a significant increase in our production guidance for 2006. The start-up of production from Tucker, which is not included in our 2006 production guidance, will lead to significant growth in 2007.

Q6

Husky's proven reserves were approaching 1 billion barrels of oil equivalent at the end of 2005. What is the Company's strategy to increase its oil and gas reserves in the coming year?

Proven reserves were 985 million barrels of oil equivalent at the end of 2005, an increase of 8 percent compared to the previous year, excluding the heavy oil revision in 2004. White Rose and Tucker accounted for the bulk of the increase. Proven reserves however, represented less than 18 percent of Husky's total proven, probable and possible reserves which amounted to 5.6 billion barrels of oil equivalent at the end of 2005.

This significant resource base provides a strong foundation for continued growth in proven reserves and production as the Company executes its exploitation and development strategy offshore Canada's East Coast, in the oil sands and internationally. Successful exploration and acquisition activities should add further to the resource base over time.

Q7

How is Husky going to reduce operating expenses in view of the market trend of increasing costs?

Full year operating costs for 2005 were $8.12 per barrel of oil equivalent, compared with $7.32 per barrel of oil equivalent in 2004. Costs were impacted by increased fuel and power costs, higher trucking, servicing and maintenance rates and weather delays.

Husky will continue to focus on the controllable elements of operating costs such as trucking, service and maintenance costs. This will be achieved by expanding the pipeline system to support production growth, and optimizing service and maintenance schedules. When White Rose attains peak production in 2006, operating costs should average approximately $3.00 to $3.50 per barrel. This will help improve the corporate cost average.

Q8

Early in 2005 Husky announced the Summit Creek discovery in the Northwest Territories. The B-44 location, in which Husky has a 29.5 percent working interest, tested at a rate of approximately 10,000 barrels of oil equivalent per day. What are the next steps for developing this location?

Summit Creek B-44 represents the first hydrocarbon discovery in the Central Mackenzie Valley since Norman Wells was discovered in 1920.

Husky and its partners hold EL 397 and adjacent lands totalling 2,400 square kilometres. Husky completed a 200-kilometre 2-D seismic program on EL 397 in 2005 and commenced drilling of two wells in the Summit Creek area in January 2006. Summit Creek K-44 will appraise the discovery encountered in the Summit Creek B-44 well and the Stewart D-57 exploration well will evaluate multiple zones. As these locations are in a remote area with limited winter-only drilling access, well testing may have to be deferred until the next winter drilling season.

Q9

How does Husky plan to develop its 200,000 barrel per day Sunrise Oil Sands Project and control costs if most of its peers are experiencing difficulty in developing their projects on-budget and on-schedule?

Husky recognizes the challenge of developing the Sunrise Project in the current high level of activity environment. Husky received regulatory approval for the 200,000 barrel per day upstream development and we are currently reviewing the project to determine the optimal design capacity. We intend to develop Sunrise in stages that will employ our project management expertise acquired from developing our Tucker and White Rose Projects, maximize modularization and access global engineering resources.

The project will be developed with the strict financial discipline and diligence that we have used in our other projects. We are working on a full-cycle economic model with a focus on upstream development, upgrading, transportation and marketing of the bitumen from Sunrise.

Q10

What are Husky's plans with respect to upgrading and refining the production from its Tucker and Sunrise leases? Will the production be processed at the Lloydminster Upgrader?

Husky understands the midstream and downstream challenges inherent in developing our oil sands leases. The production from the Tucker Oil Sands Project will be processed at the Lloydminster Upgrader. The Lloydminster Upgrader is on schedule to reach 82,000 barrels per day later in 2006 after completion of the debottlenecking projects. After completion, Husky will have 109,000 barrels per day of processing capacity in the Lloydminster area including 27,000 barrels per day of refining capacity from its asphalt refinery.

For the Sunrise Oil Sands Project, the Company is completing a review of its alternatives for full-cycle economics including downstream investments to ensure we capture the full integrated value of Sunrise.

Q11

How does the Husky Heavy Oil Upgrader contribute to the value chain of your integration? Do you have plans to expand this facility to keep pace with your growth in heavy oil and plans for the oil sands?

The Upgrader's strong contribution to Husky's net earnings reflects the value of our integration by capturing the high price differential between the heavy oil feedstock processed through the Upgrader and the premium synthetic crude oil produced.

This midstream asset substantially eliminates Husky's exposure to volatile heavy and light oil price differentials. By upgrading our heavy oil into higher valued synthetic oil, we effectively become a light oil producer.

The Upgrader as originally designed had a production throughput capacity of 52,000 barrels per day. Through various debottlenecking projects we have expanded the plant and are on track to reach 82,000 barrels per day in 2006. The volumes from Tucker will be processed at the Upgrader as the quality of the production is similar to the heavy oil currently being processed. With our projected growth in heavy oil and the addition of the Tucker volumes by the end of 2006, we are reviewing the feasibility of expanding the facility.

Q12

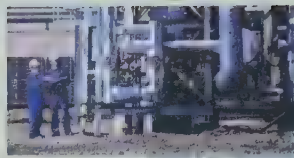
Now that Husky has completed the White Rose project ahead of schedule and on-budget, what other projects or plans is Husky considering for development offshore the East Coast of Canada?

Husky's priority is to achieve peak production of 100,000 barrels of oil per day at the White Rose oil field.

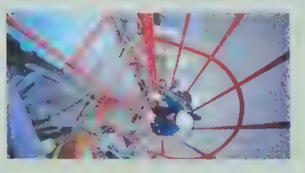
Husky's strategy is focused on exploiting our existing core assets through delineation drilling to further define the White Rose oil and natural gas fields. Adding reserves and additional production would be an effective use of our production infrastructure in the Jeanne d'Arc Basin.

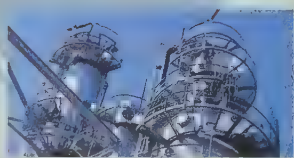
Husky is planning to increase the Company's asset base by acquiring additional exploration acreage, pursuing acquisition opportunities and continuing a strong exploration program.

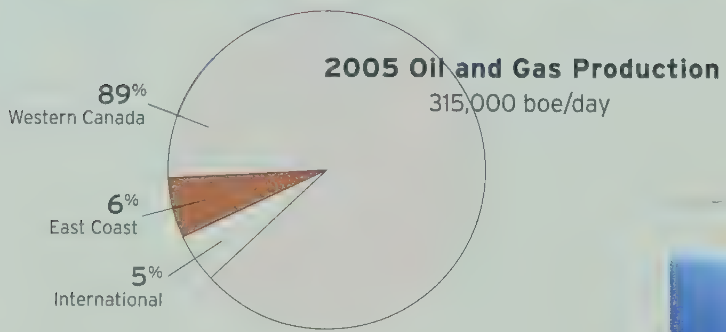
Report on Operations

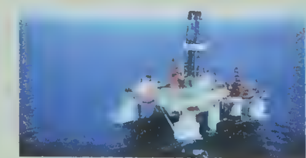


As one of Canada's largest energy and energy-related companies, Husky has built a diversified business portfolio within Canada and internationally. Most of Husky's producing assets and midstream and refined products facilities are in Western Canada. Canada's East Coast is the site of Husky's most recent achievement, first oil at the White Rose oil field offshore Newfoundland and Labrador.



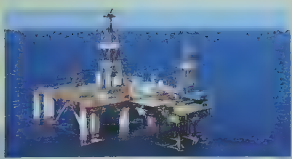


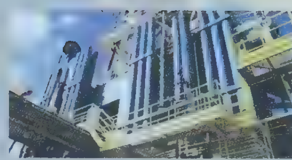




ASSETS

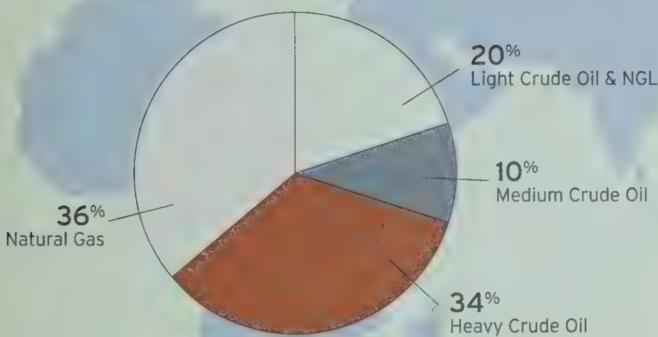
1 **Western Canada** Western Canada Sedimentary Basin	2 **Heavy Oil** Lloydminster	3 **Oil Sands** Tucker Sunrise

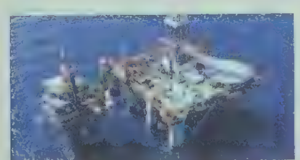





Husky is growing its asset portfolio outside of Canada. Husky has production operations offshore China and extensive exploration acreage in the Madura Straits, offshore Indonesia.

2005 Product Mix



4 **Canada's East Coast**
White Rose
Terra Nova

5 **International**
Offshore China
Offshore Indonesia

6 **Midstream**
Lloydminster Upgrader
Hardisty Terminal
Pipeline Infrastructure
Meridian Cogeneration Power Plant

7 **Refined Products**
Lloydminster Asphalt Refinery
Prince George Light Oil Refinery
Lloydminster & Minnedosa Ethanol Plants

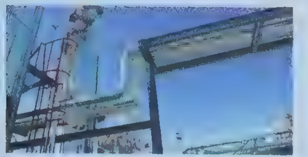
1 Western Canada Conventional Production

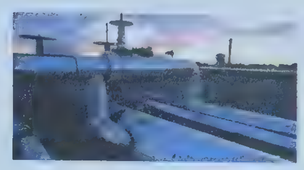
Western Canada is a mature basin but with Husky's significant land and pipeline infrastructure, and geological and geophysical knowledge there are many tight gas and gas from coal opportunities. With improved oil recovery technologies, there is still potential in the basin. If the right opportunities are selected, there are still good returns to be made.

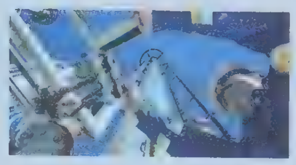
R.S. (Bob) Coward, Vice President, Western Canada Conventional Production

Financing Husky's Growth on our Western Front

2005 Production	Proved and Probable Reserves	Acreage
175,600 barrels of oil equivalent per day	754 million barrels of oil equivalent as of December 31, 2005	7.54 million acres







Production

Husky plans to drill low-risk shallow gas prospects in the northwestern Alberta plains, and in southern Alberta and Saskatchewan that utilize our existing infrastructure, and higher-risk, but greater potential, deep gas prospects in the British Columbia and Alberta foothills.

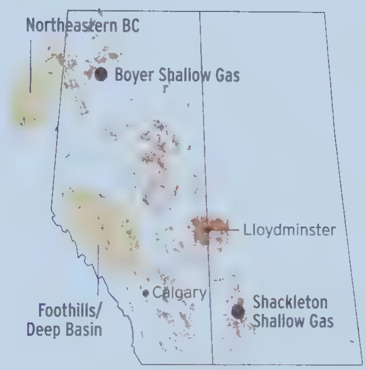
We have the potential to grow gas volumes from our existing east central and southern Alberta leases through a joint venture to extract natural gas from coal (NGC). During 2005, natural gas volumes increased to 10 million cubic feet per day. We plan to drill 300 wells in 2006 to increase NGC production to 35 million cubic feet per day.

Husky will start its second enhanced oil recovery project in June 2006 with an alkaline-surfactant-polymer (ASP) flood in the mature, water-flooded Taber Mannville B Pool. The $70 million pilot project received $10 million in royalty relief under the Government of Albérta's Innovative Energy Technologies Program.

Exploration

In May 2005, Husky became operator of Block EL 397 containing the Summit Creek B-44 discovery in the Central Mackenzie Valley area of the Northwest Territories. Test rates showed an estimated natural gas production of 20 million cubic feet per day and 6,000 barrels per day of light oil and condensate. It is the first significant oil discovery in the Central Mackenzie Valley since 1920. Husky and its co-venturers hold 2,400 square kilometres in the area. During the year Husky completed a 2-D seismic program and plans to drill two wells in the Summit Creek area in 2006.

Husky plans to drill 250 exploratory wells in 2006, targeting a variety of plays in the foothills, deep basin, northeastern British Columbia and Alberta plains, including natural gas from coal.



WESTERN CANADA CONVENTIONAL OIL & GAS ASSETS

- *Average working interest: 90%*
- *2005 average daily production:*
  - *Light oil and NGL: 31 mbbls/day*
  - *Medium oil: 31 mbbls/day*
  - *Natural gas: 680 mmcf/day*
- *Proved and probable natural gas reserves: 2,542 bcf*
- *Proved and probable oil and NGL reserves: 330 mmbbls*
- *Oil and gas landholdings: 7.54 million acres*

OUTLOOK

- *Fully load our production infrastructure and farm out inactive lands*
- *Maintain reserve replacement over 100%*
- *Maintain an average reinvestment ratio of 50% to 60%*
- *Focus on health, safety and environmental performance*
- *Focus on controlling operating and capital costs*

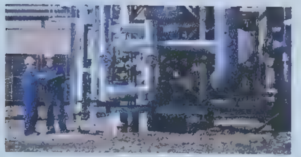
2 Heavy Oil

While the Western Canada Sedimentary Basin's light and medium oil production levels have reached maturity, heavy oil and oil sands remain the growth area for liquid production. The Lloydminster area has become the focus for major expansion in heavy oil operations. Husky's extensive landholdings and operations in the area ensure that we are well placed to lead this growth.

E.T. (Ed) Connolly, Vice President, Heavy Oil

Canada's Largest Heavy Oil Producer

2005 Production	Proved and Probable Reserves	Acreage
106,000 barrels per day	**291 million** barrels as of December 31, 2005	**1.57 million** acres



Husky has been a pioneer in the development and production of heavy oil and remains the dominant player. Our position is enhanced by synergies with our nearby heavy oil upgrader and asphalt refinery, and 1.1 million acres of undeveloped and 415,000 acres of developed landholdings.

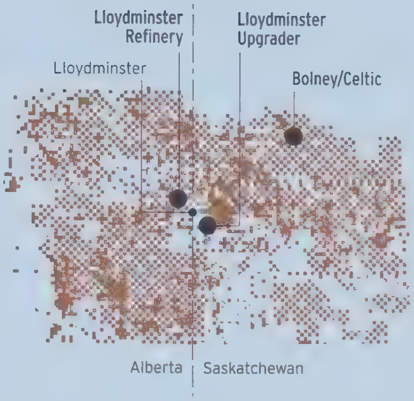
Wet weather during much of the year impacted our drilling program and production capacity. A major portion of our drilling program was delayed until the last quarter of 2005 and production dropped some 10,000 barrels per day.

Despite production disappointments Husky made some significant achievements in controlling costs. Our single-well monitoring and production optimization initiative reduced our annual servicing costs by some $15 million. By substituting propane and purchased gas with natural gas recovered from our wells, costs have been reduced by $5 million. We have also improved the efficiency of our trucking, maintenance and sand handling systems to save an additional $14 million per year.

Development and Production

Husky plans to replace 100 percent of our production by drilling 500 wells during 2006. Production at Celtic/Bolney will be increased to 14,000 barrels per day during the year and the Lashburn thermal project will be expanded to produce 4,000 barrels per day by late 2007.

We plan to become the low-cost operator and developer of heavy oil by implementing more efficient transportation solutions such as expanded pipelining and improved trucking, utilizing technology to optimize thermal and cold-enhanced oil recovery, increasing exploration efforts in undeveloped areas, and the effective development of the remaining main pools.



HEAVY OIL ASSETS

- *Average working interest: 98%*
- *2005 average production: 106 mbbls/day*
- *Proved and probable reserves: 291 mmbbls*
- *Landholdings: 1.57 million acres*

OUTLOOK

- *Grow heavy oil production by over 10% in 2006*
- *Drill 500 wells*
- *Seek new opportunities to implement thermal recovery technology and develop cold enhanced oil recovery technology*
- *Focus on health, safety and environmental performance*
- *Focus on controlling operating and capital costs*

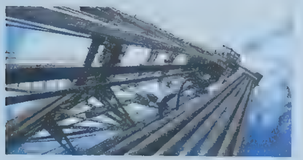
3 Oil Sands

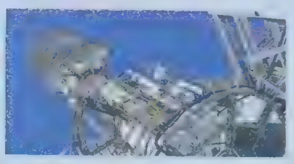
Husky's oil sands leases are a great asset for the Company. Tucker, our first foray into the oil sands, is on-time and on-budget with first oil anticipated by the end of 2006. With regulatory approval in place for our 200,000 barrel per day Sunrise Project, Husky is positioned to become a pre-eminent oil sands player.

G.P. (Garry) Mihaichuk, Vice President, Oil Sands

Tucker on Schedule. Sunrise Approved

Tucker and Sunrise Estimated Production	Tucker and Sunrise Potential Resource	Tucker and Sunrise Acreages
230,000 barrels per day	3.5 billion barrels as of December 31, 2005	67,714 acres





Tucker

Construction on the Tucker Oil Sands Project, 30 kilometres northwest of Cold Lake, Alberta, began in the fall of 2004. The project is anticipated to be commissioned and producing oil using a steam-assisted gravity drainage (SAGD) process by the end of 2006. During the 35-year project life we expect to produce 348 million barrels of bitumen with peak production of more than 30,000 barrels per day. Tucker is very attractive for Husky as it is near our Cold Lake pipeline system and heavy oil upgrader in Lloydminster, Saskatchewan.

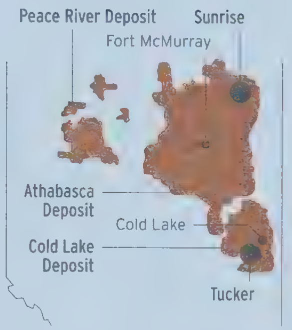
The project has met key milestones and stayed within budget. This is a major achievement given the cost pressures and wet weather the industry experienced in 2005. It results from action taken to develop project scope and secure critical contracts and resources prior to construction.

Sunrise

Husky estimates that the Sunrise Oil Sands Project, 60 kilometres northeast of Fort McMurray, Alberta, could produce 3.2 billion barrels of bitumen over a 40-year period. Excellent reservoir quality and an average pay thickness of over 40 metres in the first phase area of the project are expected to yield low steam-to-oil ratios and low unit operating costs. Regulatory approval for the phased development of a 200,000 barrel per day SAGD project was obtained in December 2005. The Company is progressing developmental work on the upstream side and reviewing its downstream alternatives including upgrading, refining, transportation and marketing.

Caribou and Saleski

Caribou contains 2.5 billion barrels of bitumen in place in the Clearwater sand deposits and can be developed with established techniques. Husky's landholdings at Saleski contain 16.8 billion barrels of bitumen in place in the Grosmont Carbonate formation. Pilot projects will be required to determine the optimal recovery method.



TUCKER

- *Working interest: 100%*
- *Capital cost to first oil: $500 million*
- *Contract: Lump sum for central processing facility*
- *Commence steam injection: Q3 2006*
- *First production: 3 to 6 months after commissioning steam injection*
- *Proved reserves: 48 mmbbls*
- *Proved, probable and possible reserves: 348 mmbbls*
- *Anticipated production: 30+ mbbls/day*

SUNRISE

- *Working interest: 100%*
- *Probable reserves: 850 mmbbls*
- *Probable and possible reserves: 3.2 billion bbls*
- *Peak production: 200,000 bbls/day*

OUTLOOK

- *Establish commercial in-situ bitumen production at Tucker*
- *Develop Sunrise in coordination with the required regional infrastructure, marketing and transportation solutions*

OIL SANDS LEASES

Net acreage: 425,930 acres

Lease	*Original Bitumen in Place*
Tucker	*1,270 mmbbls*
Sunrise	*10,600*
Caribou	*2,500*
Saleski	*16,800*
Others	*2,380*
Total	*33,550 mmbbls*

4 Canada's East Coast

Husky successfully achieved first oil for White Rose ahead of schedule and on-budget. White Rose represents a significant accomplishment and provides Husky with a platform for future growth. Satellite fields and future finds from successful delineation and exploration drilling in the area will be tied into the White Rose infrastructure, adding production and reserves, and extending field life.

R.B. (Ruud) Zoon, Vice President, East Coast Operations

A Platform for Future Growth: White Rose in Production

Total Terra Nova and White Rose 2005 Production

17,200

barrels per day

Terra Nova and White Rose Proved and Probable Reserves

207 million

barrels as of December 31, 2005

Jeanne d'Arc Basin Acreage

1.37 million

acres

Canada's East Coast plays a key role in achieving our corporate medium and long-term production targets. In addition to our holdings in the White Rose and Terra Nova developments, we are one of the largest holders of offshore exploration acreage in the Jeanne d'Arc Basin. With White Rose on-stream, we anticipate to significantly increase production from the East Coast to between 60,000 and 67,000 barrels per day net to Husky in 2006. Our growth strategy is focused on fully exploiting and building on our existing core asset positions. This will include both delineation and exploration drilling in 2006.

Overall, we are targeting to increase production to 100,000 barrels per day by 2010 by developing White Rose satellite tie-backs and additional Terra Nova reserves. Natural gas exports are expected to significantly add to production in the longer term.

White Rose

First oil from the White Rose Project was achieved in November 2005. Gross peak production is anticipated to be 100,000 barrels per day, 72,500 net to Husky.

Completed on-budget at a cost of $2 billion, the White Rose Project has demonstrated Husky's ability to successfully execute a large capital project. During 2006, further delineation of gas reserves in the area will support feasibility studies into the potential for natural gas exports.

Terra Nova

In 2005, Husky's production share averaged 12,400 barrels of oil per day. At the end of the year, remaining proved reserves were estimated at 20 million barrels and probable at 13 million barrels. During 2006, we will support the joint venture in improving the operational performance of the *Terra Nova FPSO* vessel and in further delineating the Terra Nova reserves.

WHITE ROSE

- *Working interest: 72.5%*
- *Husky's share:*
  - *Proved and probable reserves: 173 mmbbls*
  - *Peak production: 72,500 bbls/day*
- *Number of wells: 19 - 21*
- *Field life: 12 - 15 years*

HOLDINGS

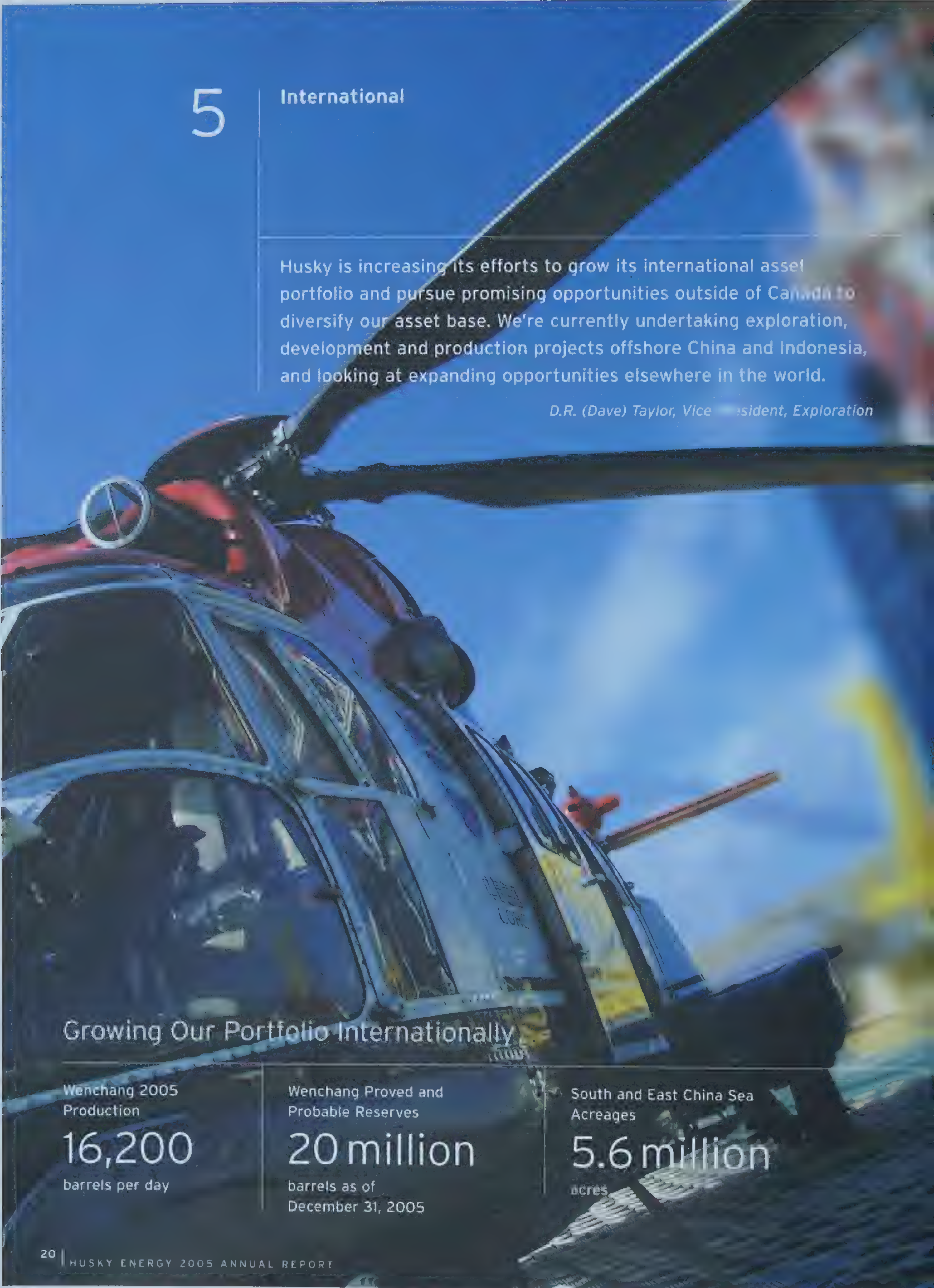
- *Significant discovery areas: 15*
- *Exploration licences: 11*
- *Production licences: 2*
- *Exploration acreage: more than 1 million acres*

OUTLOOK

White Rose
- *Delineate White Rose oil and gas reserves*
- *Husky's share in 2006: average 50,000 - 55,000 bbls/day*
- *Focus on controlling operating and capital costs*
- *Focus on health, safety and environmental performance*

Terra Nova
- *Working interest: 12.51%*
- *Delineate Terra Nova Far East South reserves*
- *Husky's share in 2006: average 10,000 - 12,000 bbls/day*

Exploration
- *Evaluate holdings in the Jeanne d'Arc Basin*



5

International

Husky is increasing its efforts to grow its international asset portfolio and pursue promising opportunities outside of Canada to diversify our asset base. We're currently undertaking exploration, development and production projects offshore China and Indonesia, and looking at expanding opportunities elsewhere in the world.

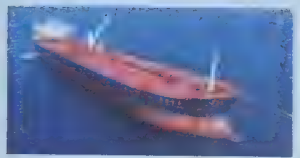
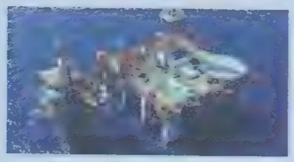
D.R. (Dave) Taylor, Vice President, Exploration

Growing Our Portfolio Internationally

Wenchang 2005 Production
16,200
barrels per day

Wenchang Proved and Probable Reserves
20 million
barrels as of December 31, 2005

South and East China Sea Acreages
5.6 million
acres

China

Husky's acquisition of Wenchang, in the South China Sea, in 2002 provided a production base in Southeast Asia for the Company to build on. While Wenchang is now a mature field it has been highly profitable, enabling Husky to position itself with good exploration prospects near major oil and natural gas markets in China. We still see opportunities in the Wenchang field and plan to drill four infill development wells in 2006.

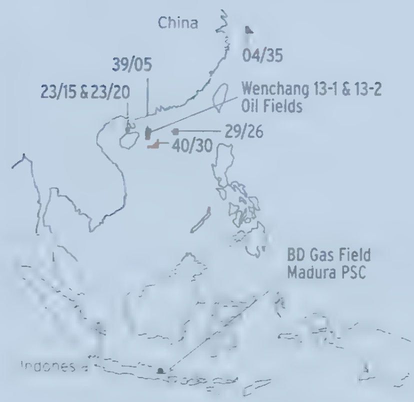
During 2006, our exploration plan is to drill in Block 29/26, in the South China Sea, at a water depth of 1,300 metres where we have identified a large gas-prone structure. We have also identified two gas-prone structures in Block 04/35, 300 kilometres east of Shanghai, where we plan to drill an exploration well in 2006.

Indonesia

Husky's production sharing contract (PSC) in the Madura Strait offshore Indonesia offers great potential. The PSC contains two discoveries, the BD gas field and the MDA gas field, which also offer significant exploration promise.

The BD field has discovered resources of 515 billion cubic feet of natural gas and 23 million barrels of natural gas liquids, which includes probable reserves of 167 billion cubic feet of natural gas and 9 million barrels of oil and natural gas liquids, based on the current term of the PSC. We plan to have approval for a development plan, a gas sales agreement and an extension to the production sharing agreement in 2006. With the signing of the PSC extension we anticipate that an additional 348 billion cubic feet of natural gas and 14 million barrels of natural gas liquids will be classified as probable reserves.

Development planning for exploiting the BD field is under way with first production expected in late 2008 or early 2009.



WENCHANG PROJECT SUMMARY

- *Working interest: 40%*
- *Husky's share:*
  - *Proved and probable reserves: 20 mmbbls*
  - *2005 average production: 16 mbbls/day*
- *Field life: 10 – 12 years*

INDONESIA

Madura BD Field
- *Working interest: 100%*
- *Discovered resource:*
  - *Natural gas: 515 bcf*
  - *Liquids: 23 mmbbls*
  - *Production estimate: 100 mmcf/day plus 6,000 bbls/day of natural gas liquids*
- *First production: 2008*

MDA Field
- *Discovered resource:*
  - *Natural gas: 150 bcf*

OUTLOOK

China
- *Additional development drilling at Wenchang*
- *Continue exploration on existing blocks*

Indonesia
- *Commercialize the Madura BD field*
- *Determine economic viability of Madura MDA field*
- *Pursue exploration potential on Madura Strait block and other expansion opportunities*

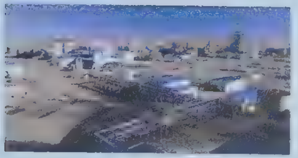
6 Midstream

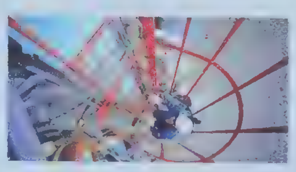
The year 2005 was a record year with growth in all of Husky's midstream operations. Our midstream assets are structured to minimize cash flow volatility. They include a heavy oil upgrader, pipelines, commodity marketing, electricity generation, and crude oil and natural gas storage and processing facilities that connect with key North American transportation systems.

D.R. (Don) Ingram, Senior Vice President, Midstream & Refined Products

Synergies within the Value Chain

Upgrader Throughput Capacity	2005 Commodity Volumes	Pipelines
77,000	950,000	2,050
barrels per day	barrels of oil equivalent per day	kilometres





Heavy Oil Upgrader

Husky's heavy oil upgrader at Lloydminster, Saskatchewan, processes heavy oil feedstock into premium quality synthetic crude oil for sale to refiners in Eastern Canada and the United States. During the year it processed 66,600 barrels of heavy oil per day. Debottlenecking projects are under way to increase throughput capacity to 82,000 barrels of heavy oil and diluent per day by the end of 2006. The Company is also undertaking front-end engineering in preparation for a possible expansion to increase the upgrader's throughput capacity to 140,000 barrels per day.

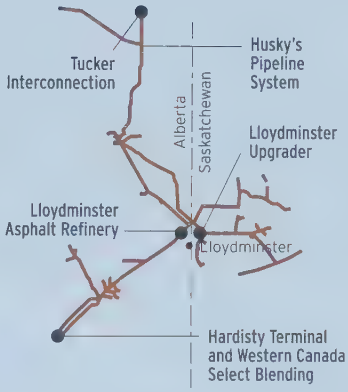
Facilities and New Ventures

Husky owns and operates a 2,050-kilometre pipeline system that extends from Cold Lake, Alberta to Lloydminster and down to our terminal at Hardisty, Alberta. The Hardisty Pipeline Terminal handles crude for Husky and third parties, and injects a crude oil stream, composed of several crude oil and diluent streams, known as Western Canadian Select, into the Enbridge, IPF and KinderMorgan pipeline systems. The terminal handles in excess of 430,000 barrels per day of product ranging from light and synthetic to blended heavy crudes, and accounts for over 25 percent of the total volume of crude oil exports from Western Canada.

Commodity Marketing

By capturing that portion of the value chain between the well head and the end-user, Commodity Marketing aggregates, supplies, transports and stores proprietary and third-party crude oil, natural gas, liquids, sulphur and petroleum coke. Husky's Commodity Marketing group took the lead in marketing oil from White Rose to refiners in Eastern Canada, and the U.S. East and Gulf Coasts.

Commodity marketing volumes exceeded 950,000 barrels of oil equivalent per day during 2005. New sales and financial records were set for petroleum coke, crude oil and natural gas.



FACILITIES

- *Upgrader throughput capacity: 77,000 bbls/day*
- *Pipeline system: 2,050 km*
- *Crude oil storage capacity: 2.3 mmbbls*
- *Natural gas storage capacity: 25 bcf*
- *Cogeneration:*
  - *215 MW facility, Lloydminster, S.K.: 50% ownership interest*
  - *90 MW facility, Rainbow Lake, A.B.: 50% ownership interest*

OUTLOOK

- *Increase natural gas storage business*
- *Expand transmission pipelines*
- *Increase throughput of Western Canada Select Blend*
- *Complete Lloydminster upgrader debottlenecking project*

7

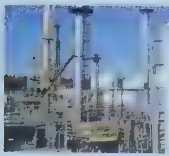
Refined Products

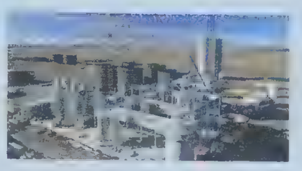
By every possible measure 2005 was a great year for Refined Products. Our light oil strategy continued to show results by increasing throughput per retail outlet, reducing operating unit costs, rolling out our "Husky Market" retail concept, and promoting ethanol-blended fuels. These efforts were supported by our Clean Fuels Project at the Prince George refinery, and construction of two ethanol plants to meet the demand for ethanol-blended fuels.

D.R. (Don) Ingram, Senior Vice President, Midstream & Refined Products

Redefining our Market Share

Throughput Capacity Prince George Refinery	Throughput Capacity Lloydminster Asphalt Refinery	Total Station Outlets
10,000	27,000	515
barrels per day	barrels per day	across Canada





Retail Network

Husky and Mohawk-branded fuels are marketed through more than 500 retail outlets, travel centres and bulk distributors from Vancouver Island to Ontario. During 2005, average throughput per location was 4.6 million litres or almost 9 percent higher than 2004. Throughput per location has increased 27 percent over the past four years. Ancillary margin from sales other than fuel was a record $34 million or 13 percent greater than 2004.

Prince George Light Oil Refinery

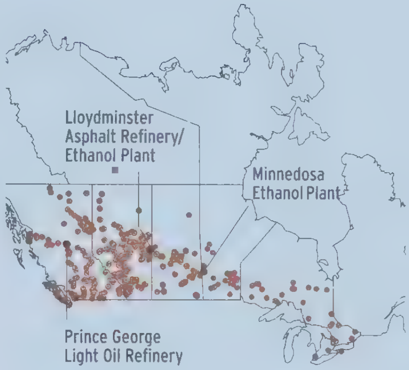
Unleaded gasoline, seasonal diesel fuels, butane and propane mix, and heavy fuel oil are produced at our Prince George Refinery. Low-sulphur gasoline production commenced in August following completion of phase one of our Clean Fuels Project. Refinery throughput will increase to 12,000 barrels per day when phase two, an upgrade to produce low-sulphur diesel fuel and a refinery expansion, is completed in mid-2006.

Ethanol Production

Husky plans to become Western Canada's largest producer of ethanol. Currently, we produce 10 million litres of ethanol per year at our facility in Minnedosa, Manitoba. This figure will increase to 140 million litres per year when our 130 million litre per year plant at Lloydminster, Saskatchewan is commissioned in mid-2006 and to 260 million litres per year when an expansion of the Minnedosa plant becomes operational in late 2007.

Asphalt Refining and Marketing

The asphalt refinery in Lloydminster, Alberta produces asphalt products used for road construction and maintenance, and building materials, in addition to locomotive blendstock and specialized oil field products.



PRODUCTION FACILITIES

- *Emulsion Plants/ Asphalt Terminals: 8*
- *Prince George Refinery: 10,000 bbls/day*
- *Lloydminster Asphalt Refinery: 27,000 bbls/day*
- *Minnedosa Ethanol Plant: 10 million litres/year*

OUTLETS

- *Total outlets: 515*

OUTLOOK

- *Increase throughput per location by 3.5%*
- *Increase ancillary income by 2.5%*
- *Increase asphalt volumes by 4%*
- *Commission the Lloydminster Ethanol Plant in mid-2006*
- *Commission the Minnedosa Ethanol Plant in Q4 2007*
- *Upgrade the Prince George refinery to produce low-sulphur gasoline and diesel fuels*

Social Responsibility

In today's increasingly complex and integrated environment, the actions of one organization can impact other organizations and individuals. Thus the health and safety of Husky's employees and the public, and environmental stewardship are core fundamental values to how our Company operates its business.

K.W. (Wendell) Carroll, Vice President, Corporate Administration

Health, Safety and Environment

Reclamation Certificates and Releases	Days Worked without a Lost Time Accident at Heavy Oil Upgrader	Recognition One of Alberta's
641	4.4 million	Top 20
received in 2005	person-days (9.5 years)	Employers

Safety and Education

Higher activity levels in the oil and gas sector have led to a scarcity of skilled and experienced workers. To ensure a safe workplace, Husky is working with our contractors and the industry in developing safety training and procedures for workers.

The Company is impacted by the shortage of qualified potential employees as we proceed to commissioning several of our major projects. We are working with other interested organizations on a process to recognize educational and professional qualifications from foreign institutions.

Environmental Stewardship

To minimize the impact of our operations on the environment, Husky has developed a well and facility "life cycle" approach for our assets. It begins with documenting public consultation and stakeholder commitments, establishing clarity with regulators, and monitoring and addressing site-specific environmental issues and their reclamation or remediation solutions until the sites are formally abandoned.

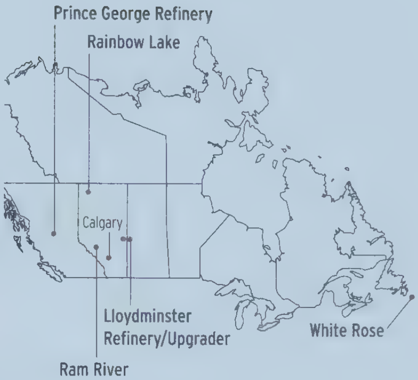
Our well site reclamation program received over 641 reclamation certificates and releases from regulators in 2005. We also have an extensive reclamation program to restore our older sites in our midstream and downstream operations and make them commercially viable.

Public Consultation

Husky's proactive approach to meeting with stakeholders, discussing their concerns and balancing their interests to seek lasting solutions has ensured solid public support for constructing our ethanol plants in Lloydminster, Saskatchewan and Minnedosa, Manitoba, and our Tucker Oil Sands Project.

Regulatory Compliance

Husky is continually improving its health, safety and environmental policies and practices to comply with current and anticipated regulatory changes. The Company emphasizes with each of our employees and contractors, from the senior management level to the field worker, that each has responsibility for protecting the health and safety of their work colleagues and the public. In addition, our health, safety and environmental management systems are constantly updated to ensure that we meet or exceed our responsibilities.



RECOGNITION

Husky was honoured to receive the following:

- *Recognition as one of Alberta's Top 20 Employers*
- *Alberta Human Rights & Citizenship Commission Diversity Leadership of Distinction Award*
- *CPR Chemical Shipper Safety Award*

OUTLOOK

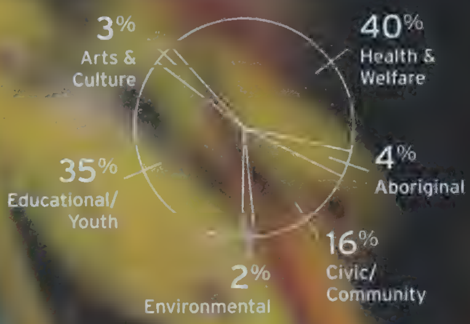
- *Exceed established health, safety and environmental standards*
- *Hire contractors who demonstrate best safety practices and environmental awareness*
- *Implement new environmental data information management system*

Community Investment

Husky prides itself on acting in a socially responsible manner and participating in the communities where we do business. Our community investment program focuses on those areas which we believe offer the greatest long-term benefits: the advancement of education, the betterment of our communities, and establishing mutually beneficial relationships with Aboriginal communities.

J.C.S. (John) Lau, President & Chief Executive Officer

2005 Charitable Donations



A Commitment to the Future

Number of Charitable Organizations	Husky and Employees Matching Donations Program	Community Investment
450+	$650,000 in 2005	$3.3 million donated to charities in 2005



Education

Husky believes that contributions to education are an investment in the future of our society, and that we can help educational institutions meet the challenge to produce knowledgeable and skilled graduates. Husky has taken a leadership role in creating educational and research opportunities at Canada's universities. In 2005, we contributed $1 million to establish two research chairs in biofuels at the University of Manitoba. The Company has also established research chairs at the University of Calgary and Memorial University, and funded educational initiatives at secondary and post-secondary educational institutions.

Community Investment

Husky's commitment to the communities where we operate is supported by our Community Investment Program. During 2005, we contributed over $3 million to more than 450 charities including $335,000 for a computerized tomography (CT) scanner for the Lloydminster Region Health Foundation and $100,000 towards the purchase of diagnostic equipment for the Cypress Regional Hospital, in Swift Current, Saskatchewan. Funds were also contributed towards community recreational facilities in Ram River, Bonnyville and Athabasca, Alberta.

Husky matches employees' donations to selected charities. Under our Annual Employee Charitable Donations Program the Company and our employees donated $650,000 to 46 charities in 2005. During the year Husky and our employees also contributed to relief efforts for the Asian tsunami disaster and participated in the Share the Magic Book drive, an initiative to improve literacy among children with learning disabilities.

Aboriginal Affairs

Many of Husky's projects are near Aboriginal communities. To ensure that the concerns of these communities are addressed we have signed agreements with 11 first nations which reflect our flexible approach in consulting with them. In addition, we have initiatives that promote educational attainment, support community wellness and foster economic development.

HUSKY HAS SIGNED AGREEMENTS WITH THE FOLLOWING FIRST NATIONS:

- *Athabasca Chipewyan*
- *Bigstone Cree*
- *Cold Lake*
- *Fort McKay*
- *Frog Lake*
- *Kehewin Cree*
- *Loon River*
- *Lubicon Lake*
- *Mikisew Cree*
- *Whitefish Lake*
- *Woodland Cree*

HONOURS AND RECOGNITION RECEIVED:

- *2005 Clearsight Wealth Management Friend of Education Award from the Canadian Council for the Advancement of Education*
- *2005 Calgary Chamber of Commerce Salute to Excellence Award*
- *Lloydminster Community Contribution Award*

OUTLOOK

Husky will continue its commitment to social responsibility by:

- *encouraging the advancement of education*
- *improving the quality of life in the communities where we operate*
- *focusing on initiatives that maximize the value of our contributions and provide long-term benefits*
- *providing opportunities for Aboriginal communities to share in the benefits of economic development*

M

Husky Energy Inc.

Management's Discussion and Analysis

Table of Contents

Management's Discussion and Analysis

February 16, 2006

Introduction

Intention of Management's Discussion and Analysis ("MD&A")

This MD&A is intended to provide a wide range of readers with information explaining Husky's financial and operational performance against performance in prior periods and expected or planned performance. It also describes our ability to deliver expected results from our current plans.

Review by the Audit Committee

This MD&A was reviewed by the Audit Committee and approved by Husky's Board of Directors on February 16, 2006. Any events subsequent to that date could conceivably materially alter the veracity and usefulness of the information contained in this document. Husky may, but is not obligated, to provide updates to its forward-looking statements in its subsequent interim MD&A filings or in subsequent news releases filed or furnished to regulatory agencies.

Additional Husky Documents that should be considered by the Reader

This MD&A should be read in conjunction with the Consolidated Financial Statements and related Notes. The readers are also encouraged to refer to Husky's interim reports filed in 2005, which contain MD&A and Consolidated Financial Statements, and Husky's Annual Information Form filed separately with Canadian regulatory agencies and Form 40-F filed with the Securities and Exchange Commission ("SEC"), the U.S. regulatory agency. These documents are available at www.sedar.com and www.sec.gov, respectively.

Use of Pronouns and Other Terms Denoting Husky

In this MD&A the pronouns "we", "our" and "us" and the term "Husky" denote the corporate entity, Husky Energy Inc. and its subsidiaries on a consolidated basis.

Standard Comparisons in this Document

Unless otherwise indicated, the discussions in this MD&A with respect to results for the year ended December 31, 2005 are compared with results for the year ended December 31, 2004 and, similarly discussions with respect to Husky's financial position as at December 31, 2005 are compared with its financial position at December 31, 2004.

Reclassifications and Materiality for Disclosures

Certain prior year amounts have been reclassified to conform with current year presentation. Materiality for disclosures is determined on the basis of whether the information omitted or misstated would cause a reasonable investor to change their decision to buy, sell or hold the securities of Husky.

Additional Reader Guidance

The Consolidated Financial Statements and all financial information included and incorporated by reference in this MD&A have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The effect of significant differences between Canadian and United States accounting principles is disclosed in Note 19 of the Consolidated Financial Statements.

All dollar amounts are in millions of Canadian dollars, unless otherwise indicated. Unless otherwise indicated, all production volumes quoted are gross, which represent Husky's working interest share before royalties. Prices quoted include or exclude the effect of hedging as indicated. Crude oil has been classified as the following: light crude oil has an API gravity of 30 degrees or more; medium crude oil has an API gravity of 21 degrees or more and less than 30 degrees; heavy crude oil has an API gravity of less than 21 degrees.

The Company uses the terms barrels of oil equivalent ("boe") and thousand cubic feet of gas equivalent ("mcfge"), which are calculated on an energy equivalence basis whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. Readers are cautioned that the terms boe and mcfge may be misleading, particularly if used in isolation. This measure is primarily applicable at the burner tip and does not represent value equivalence at the well head.

Forward-looking Statements

This MD&A contains forward-looking statements. These statements are based on certain estimates and assumptions and involve risks and uncertainties. Actual results may differ materially. See Section 10. "Forward-looking Statements" for additional information.

1. Vision

CORE BUSINESSES

Our operations are organized into three major business segments:

Upstream

The upstream business includes the exploration for and development and production of crude oil, natural gas, natural gas liquids ("NGL") and sulphur. Our upstream operations are primarily located throughout the Western Canada Sedimentary Basin in the provinces of Alberta, Saskatchewan and British Columbia. We also have significant operations off the East Coast of Canada in the Jeanne d'Arc Basin and we are currently evaluating development potential in the Mackenzie Valley in the Northwest Territories. Outside of Canada, we are involved in China including exploration in the South China Sea near Hainan Island and the East China Sea east of Shanghai and production at Wenchang in the South China Sea. In Indonesia, we are in the early stages of developing a natural gas and NGL property in the Madura Strait offshore Java.

Midstream

The midstream business includes the operation of a heavy oil upgrader with a capacity in excess of 60,000 barrels of synthetic crude oil per day located at Lloydminster, Saskatchewan, pipeline systems with combined capacity in excess of 500,000 barrels per day in the heavy oil producing regions between Cold Lake, Alberta south through Lloydminster to Hardisty, Alberta, crude oil and natural gas storage facilities, cogeneration and commodity marketing activities.

Refined Products

The refined products business includes the operation of a recently upgraded 11,000 barrel per day full slate refinery in Prince George, British Columbia, a 25,000 barrel per day asphalt refinery in Lloydminster, Alberta and a marketing and distribution system with locations from the West Coast of Canada to the eastern border of Ontario. We are also currently at various stages of constructing ethanol plants at Lloydminster, Saskatchewan and Minnedosa, Manitoba.

OPERATING AND FINANCIAL STRATEGIES

Strategic Objective and Measures

Our mission is "to maximize returns to our shareholders in a socially responsible manner." Our strategy is to maintain financial discipline while optimizing our foundation asset base in the Western Canada Sedimentary Basin and expanding into large scale sustainable areas including oil sands, Canada's East Coast and northern basins and high potential basins offshore Southeast Asia.

Strategic Plans

Our ultimate success in achieving our long-term objectives rests on the effective execution of a number of operational and financial strategies. In this regard, we employ a planning process that provides critical consideration to our stated strategies and their possible outcomes.

Financial Objective and Strategies

- maintain debt to capitalization ratio of less than 40 percent; and
- maintain debt to cash flow from operations of less than two times.

Upstream Strategies

- increase production through plant and facility optimization, increased property development, property consolidation and decreased tie-in time;
- increase reserves through capital allocation to high-impact areas in the foothills, deep basin and northern plains;
- continue exploration on our large land position in the Jeanne d'Arc Basin and delineation of White Rose satellite prospects;
- continue exploration in China and development of Wenchang satellite prospects;
- development of Indonesian natural gas and NGL property in the Madura Strait and exploration in the area; and
- continue development of oil sands resources starting with first oil at Tucker in 2006.

Midstream Strategies

- debottleneck and enhance performance of upgrader;
- expand upgrader;
- expand pipeline and facilities;
- expand natural gas storage capacity; and
- centralize sulphur handling facilities.

Refined Products Strategies

- continue to enhance retail outlets through automation, remodeling and expanded services;
- expand commercial marketing through application of our cardlock system;
- expand ethanol production capacity;
- continue to expand manufacture and use of ethanol as an oxygenate in gasoline;
- optimize throughput per outlet;
- optimize asphalt product mix by seeking customers with high quality requirements;
- expand asphalt marketing reach and distribution network; and
- continue to debottleneck Lloydminster asphalt refinery and improve operational performance.

We believe that the execution of our current strategic plans as they relate to our current portfolio of assets will attain our mission but we will continue to pursue acquisitions and strategic alliances. Our financial objective and strategies are intended to maintain our financial condition to facilitate corporate acquisitions of a size and type that will leverage our core portfolio of assets.

CAPABILITY TO DELIVER RESULTS

We have and will maintain the financial capacity and flexibility to undertake our strategic plans including major growth projects. We have a significant resource in our workforce and will maintain it through increasing investment in training, mentoring, succession and retention programs. Our capital investments must meet an established criterion of providing a return on capital employed.

Upstream Strengths and Challenges

Our upstream business strengths consist primarily of:

- large base of producing properties in Western Canada that generally respond well to increasingly sophisticated exploitation techniques and will continue to provide a large proportion of cash flow from operations necessary to undertake current and future major growth projects;
- significant natural gas potential in the prospective deep basin, foothills and northwest plains;
- longstanding experience in the heavy oil producing areas in the Lloydminster region of Alberta and Saskatchewan combined with an extensive infrastructure;
- substantial long-term growth potential in the oil sands regions of Alberta;
- well established exploration capability in the Jeanne d'Arc Basin off the East Coast of Canada now combined with development experience with the White Rose oil field; and
- well established relationships in Southeast Asia and readily transferable exploitation expertise.

Our upstream business will likely be challenged by the following:

- increasing costs driven by the high level of oil and gas industry activity;
- labour market skills shortages;
- highly competitive environment for materials and services required to undertake large projects;
- increasing difficulty and cost of managing the natural reservoir declines of our properties in the Western Canada Sedimentary Basin;
- increasing resistance from opposing special interest groups; and
- increasing political pressure to implement fiscal regimes that might divert material cash flow available for investment.

Midstream Strengths and Challenges

Our midstream business strengths consist primarily of:

- modern reliable heavy oil upgrading facility located in the Lloydminster heavy oil producing region capable of expansion;
- reliable heavy oil pipeline systems well integrated in the Lloydminster producing region with expansion opportunities; and
- large scale marketer capable of operating as a market balancer, serving the needs of both customer and supplier.

Our midstream business will likely be challenged by the following:

- increasingly heavier crude feedstock requiring expansion and modification of our upgrader; and
- competition for pipeline capacity in heavy crude oil producing regions.

Refined Products Strengths and Challenges

Our refined products business strengths consist primarily of:

- established niche market with good marketing outlet locations and strategic land position;
- growing economies of scale for our ethanol production;
- largest manufacturer of paving asphalt in Western Canada; and
- modern asphalt manufacturing facilities located within the Lloydminster integrated infrastructure.

Our refined products business will likely be challenged by the following:

- limited access to refining margins due to lack of sufficient refining facilities;
- motor fuel and related products are increasingly being offered by other industry retailers; and
- higher transportation costs as a result of plant locations and lack of asphalt distribution network in the U.S. and Eastern Canada.

KEY PERFORMANCE DRIVERS AND MEASURES

In order to achieve our mission of maximizing returns to our shareholders in a socially responsible manner we must, in the medium- and long-term:

- find and develop proved reserves of crude oil and natural gas at a price that is competitive with our peers; and
- acquire developed and undeveloped properties which complement our portfolio and provide enhanced potential for future sustainable growth.

In the short-term we must:

- competitively optimize production through effective exploitation techniques;
- exercise selective acquisition and divestitures;
- maintain costs among the industry's lowest cost quartile performers; and
- continue to progress with the development of our major expansion projects in the Jeanne d'Arc Basin, the Alberta oil sands, the Madura Strait natural gas and NGL project and optimization and expansion assessment of the Lloydminster Upgrader.

In addition to the metrics presented by financial statements, which are prepared in accordance with Canadian GAAP, we prepare a number of additional performance indicators. Although these metrics may not be comparable with other companies they are comparable from period to period within Husky.

The overall corporate performance metrics that we monitor with respect to achieving return to our shareholders' goals are return on equity and return on average capital employed and can be found in Section 2. "Financial and Operational Overview."

The individual components of the overall metrics, which we can and must influence, are as follows:

Revenue Performance

Our revenues are primarily sensitive to changes in the commodity prices we receive for the products we sell, particularly for our production of crude oil and natural gas. Changes in these prices are caused by many factors that are outside of our control. As a result we must focus on increasing the volume of the commodities that we produce. The expected results of all plans to increase production must achieve minimum rates of return before capital is allocated. Production is subsequently measured against expected results.

Cost Performance

Cost of sales and operating expenses comprise many components, a number of which are related to our own business such as energy costs and crude oil feedstock for refining and upgrading operations and refined product purchase costs for the majority of our refined products marketing operations. Our focus is on optimizing our costs to achieve a competitive position in the industry.

Capital Performance

Before capital is allocated to a project its expected benefits must achieve an appropriate rate of return. Capital expenditures are monitored on a project by project basis and requirements for capital supplements are approved only by senior executive management. Upstream capital, which generally accounts for the majority of our capital budget, is monitored in detail to ensure that it achieves the desired result: that of increasing production, optimizing operating expenses or increasing reserves.

People Performance

We are continually investigating the factors that influence the development of a high functioning work environment and strong corporate culture. It is evident that the competitive edge that is measured with numbers is dependent on the quality of an enterprise's value-based culture. To help us foster the development of a value-based culture we monitor attrition rates as well as the results of exit interviews; we monitor training statistics and attendance records. We facilitate and maintain a work place that is respectful, inclusive, safe and socially responsible. We also keep informed of industry trends to ensure that we are well placed in the market with respect to being an employer of choice.

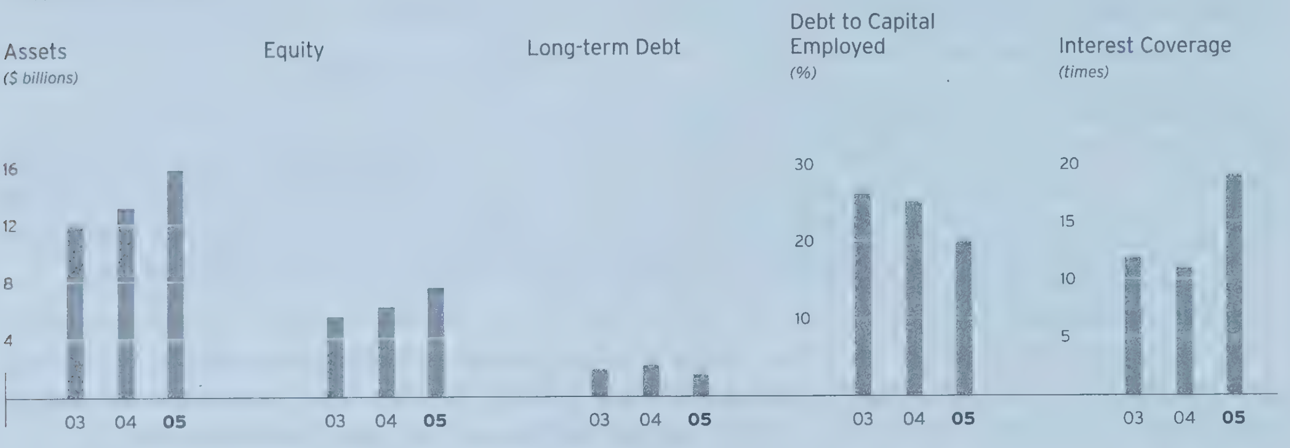
Health, Safety and Environmental Performance

We monitor all recordable accidents and all reportable environmental events that involve our operations. In addition, we conduct debriefings subsequent to events and regular audits to ensure full compliance.

2. Financial and Operational Overview

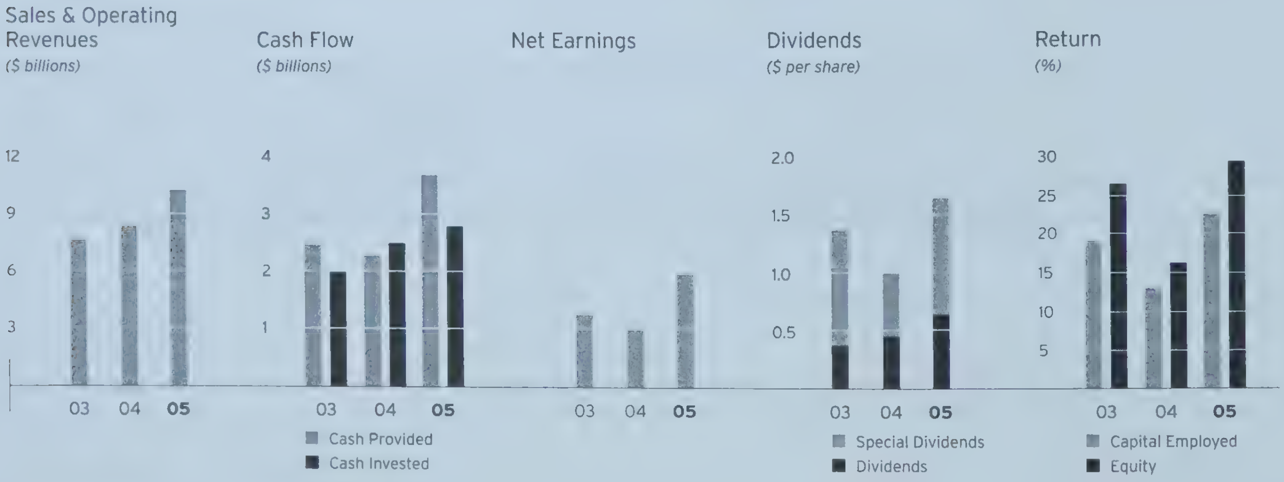
OVERVIEW

Financial Position



Comparative Shareholder Return

Financial Performance



SELECTED ANNUAL INFORMATION

Year ended December 31 *($ millions, except where indicated)*	2005	Percent Change	2004 (1)	Percent Change	2003 (1)
Sales and operating revenues, net of royalties	**$10,245**	**21**	$ 8,440	10	$ 7,658
Segmented earnings					
Upstream	**$ 1,524**	**114**	$ 713	(33)	$ 1,067
Midstream	**495**	**106**	240	30	185
Refined Products	**82**	**100**	41	28	32
Corporate and eliminations	**(98)**		12		86
Net earnings	**$ 2,003**	**99**	$ 1,006	(27)	$ 1,370
Per share					
Basic	**$ 4.72**	**99**	$ 2.37	(27)	$ 3.26
Diluted	**$ 4.72**	**99**	$ 2.37	(27)	$ 3.25
Dividends per common share	**$ 0.65**	**41**	$ 0.46	21	$ 0.38
Special dividend per common share	**$ 1.00**	**85**	$ 0.54	(46)	$ 1.00
Total assets	**$15,797**	**19**	$13,240	11	$11,949
Long-term debt excluding current portion	**$ 1,612**	**(21)**	$ 2,047	18	$ 1,730
Return on equity *(percent)*	**29.2**		17.0		26.4
Return on average capital employed *(percent)*	**22.8**		13.0		18.9

(1) 2004 and 2003 amounts as restated. Refer to Notes 3 and 11 to the Consolidated Financial Statements.

SELECTED QUARTERLY INFORMATION

	2005				2004			
($ millions, except where indicated)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Sales and operating revenues, net of royalties	**$ 3,207**	**$ 2,594**	**$ 2,350**	**$ 2,094**	$ 2,018	$ 2,191	$ 2,210	$ 2,021
Net earnings	**$ 669**	**$ 556**	**$ 394**	**$ 384**	$ 225	$ 297	$ 229	$ 255
Per share								
Basic	**$ 1.58**	**$ 1.31**	**$ 0.93**	**$ 0.91**	$ 0.53	$ 0.70	$ 0.54	$ 0.60
Diluted	**$ 1.58**	**$ 1.31**	**$ 0.93**	**$ 0.91**	$ 0.53	$ 0.70	$ 0.54	$ 0.60
Share price								
High	**$ 65.79**	**$ 69.95**	**$ 50.75**	**$ 40.49**	$ 35.65	$ 31.15	$ 28.30	$ 28.04
Low	**$ 50.50**	**$ 47.37**	**$ 35.12**	**$ 32.30**	$ 30.05	$ 25.42	$ 23.74	$ 22.73
Close (end of period)	**$ 59.00**	**$ 64.57**	**$ 48.73**	**$ 36.33**	$ 34.25	$ 30.79	$ 25.65	$ 26.20
Shares traded *(thousands)*	**38,731**	**34,521**	**46,988**	**46,370**	37,417	35,074	26,654	22,824
Dividends declared per common share	**$ 0.25**	**$ 0.14**	**$ 0.14**	**$ 0.12**	$ 0.12	$ 0.12	$ 0.12	$ 0.10
Special dividend per common share	**$ 1.00**	**$ –**	**$ –**	**$ –**	$ 0.54	$ –	$ –	$ –
Weighted average number of common shares outstanding *(thousands)*								
Basic	**424,120**	**424,049**	**423,891**	**423,791**	423,708	423,610	423,413	422,711
Diluted	**424,120**	**424,049**	**423,891**	**423,791**	423,708	423,610	425,169	424,720

THE BUSINESS ENVIRONMENT IN 2005

Husky's financial results are significantly influenced by its business environment. Risks include, but are not limited to:

- crude oil and natural gas prices;
- the price differential and demand related to various crude oil qualities;
- cost to find, develop, produce and deliver crude oil and natural gas;
- prevailing climatic conditions in our operating and marketing locations; and
- the exchange rate between the Canadian and U.S. dollar.

Average Benchmark Prices and U.S. Exchange Rate

		2005	2004	2003
WTI crude oil [1]	*(U.S. $/bbl)*	**$ 56.56**	$ 41.40	$ 31.04
Dated Brent	*(U.S. $/bbl)*	**$ 54.38**	$ 38.21	$ 28.94
Canadian par light crude 0.3% sulphur	*($/bbl)*	**$ 69.28**	$ 52.91	$ 43.56
Lloyd @ Lloydminster heavy crude	*($/bbl)*	**$ 31.07**	$ 28.75	$ 26.44
NYMEX natural gas [1]	*(U.S. $/mmbtu)*	**$ 8.62**	$ 6.14	$ 5.39
NIT natural gas	*($/GJ)*	**$ 8.04**	$ 6.44	$ 6.35
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**$ 21.01**	$ 13.65	$ 8.55
U.S./Canadian dollar exchange rate	*(U.S. $)*	**$ 0.826**	$ 0.769	$ 0.716

(1) Prices quoted are near-month contract prices for settlement during the next month.

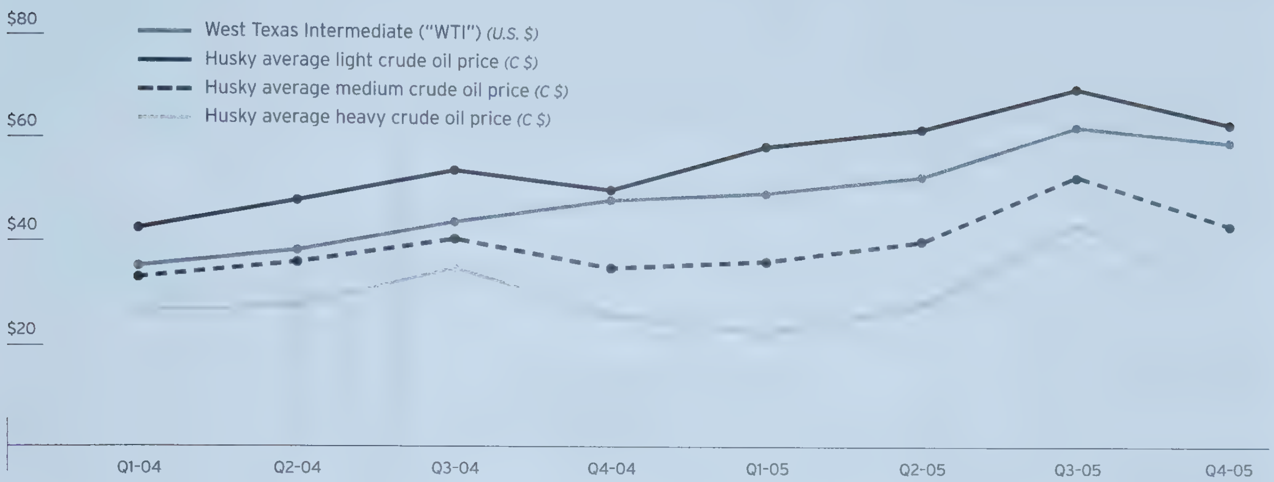
Our profitability is largely determined by the price we realize for crude oil and natural gas. All of our crude oil production and the majority of our natural gas production receive the prevailing market price. The price for crude oil is determined largely by global factors and is beyond our control. The price for natural gas is determined more by the environment in North America since virtually all natural gas production in North America is consumed by North American customers, predominantly in the United States. The price of natural gas, within its market area, is also subject to the supply and demand equation. Weather conditions may exert a dramatic effect on short-term supply and demand.

Lately the world supply and demand balance has been edging toward higher demand and as a result prices have increased substantially. This brings with it increased international effort to increase production. Notwithstanding the success of those efforts, any diminishing of global demand could set the stage for price declines.

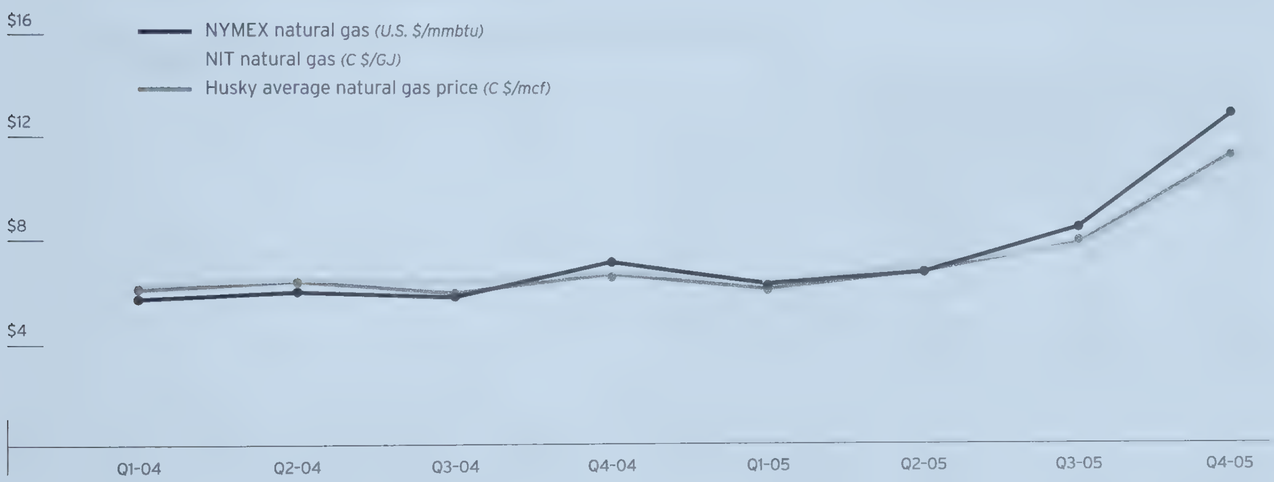
In addition, the global decline in the supply of lighter crude oil has spawned a surge in the price of heavier grades of crude oil and consequently an increase in the development and production of heavier grades of crude oil. The heavier grades trade at a discount to light crude oil refinery feedstock since they are less suited to the manufacture of motor fuels. The increased supply of heavy crude has caused a widening of the pricing differential between heavy and light crude oil since the capacity to refine heavy crude oil feedstock has not materially increased.

The majority of our crude oil and natural gas production is marketed in North America.

WTI and Husky Average Crude Oil Prices *($/bbl)*



NYMEX Natural Gas, NIT Natural Gas and Husky Average Natural Gas Prices



SENSITIVITIES BY SEGMENT FOR 2005 RESULTS

The following table is indicative of the relative effect on pre-tax cash flow and net earnings from changes in certain key variables in 2005. The analysis is based on business conditions and production volumes during 2005. Each separate item in the sensitivity analysis shows the effect of an increase in that variable only; all other variables are held constant. While these sensitivities are applicable for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or greater magnitudes of change.

Sensitivity Analysis

	2005 Average	Increase	Effect on Pre-tax Cash Flow		Effect on Net Earnings	
			($ millions)	*($/share)* (5)	*($ millions)*	*($/share)* (5)
Upstream and Midstream						
WTI benchmark crude oil price	$ 56.56	U.S. $1.00/bbl	77	0.18	50	0.12
NYMEX benchmark natural gas price (1)	$ 8.62	U.S. $0.20/mmbtu	36	0.08	22	0.05
Upgrading differential (2)	$ 30.70	Cdn $1.00/bbl	(27)	(0.06)	(17)	(0.04)
Exchange rate *(U.S. $ per Cdn $)* (3)	$ 0.826	U.S. $0.01	(58)	(0.14)	(39)	(0.09)
Refined Products						
Light oil margins	$ 0.039	Cdn $0.005/litre	16	0.04	10	0.02
Asphalt margins	$ 10.05	Cdn $1.00/bbl	8	0.02	5	0.01
Consolidated						
Year-end translation of U.S. $ debt *(U.S. $ per Cdn $)*	$ 0.858 (4)	U.S. $0.01	–	–	10	0.02

(1) Includes decrease in earnings related to natural gas consumption.

(2) Includes impact of upstream and upgrading operations only.

(3) Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items.

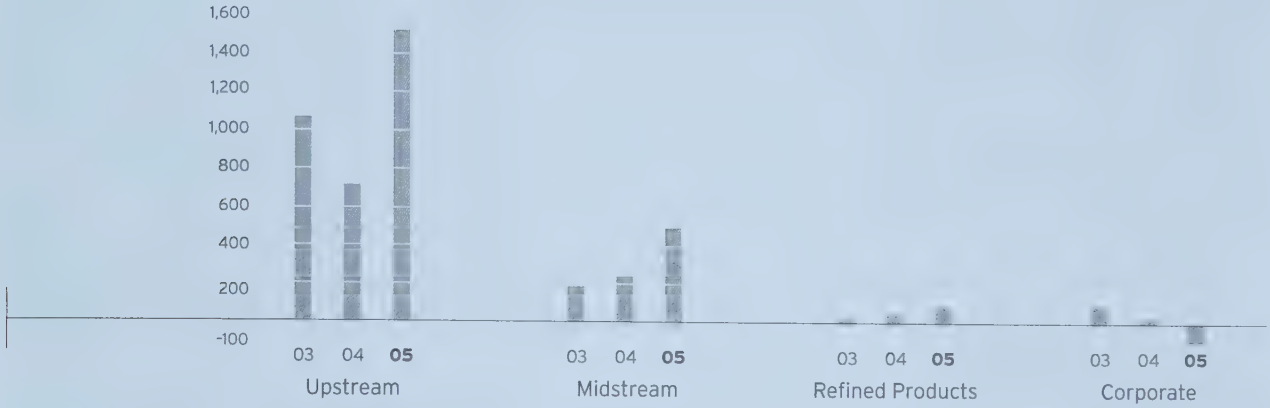
(4) U.S./Canadian dollar exchange rate at December 31, 2005.

(5) Based on December 31, 2005 common shares outstanding of 424.1 million.

3. Results of Operations

Segmented Earnings

($ millions)



UPSTREAM

Earnings Summary and 2005 Variance Analysis

Upstream Earnings Summary

Year ended December 31 *($ millions)*	**2005**	2004	2003
Gross revenues	**$ 5,207**	$ 4,392	$ 3,796
Royalties	**840**	711	584
Hedging loss	**–**	561	26
Net revenues	**4,367**	3,120	3,186
Operating and administration expenses	**1,050**	967	873
Depletion, depreciation and amortization	**1,144**	1,077	918
Income taxes	**649**	363	328
Earnings	**$ 1,524**	$ 713	$ 1,067

Upstream earnings in 2005 were $811 million higher than in 2004 primarily due to the following factors:

- higher natural gas and crude oil prices increased 2005 revenue by $947 million; and
- absence of commodity price hedging in 2005; 2004 hedging was primarily on 85 mbbls/day of crude oil at a strike price of U.S. $27.46.

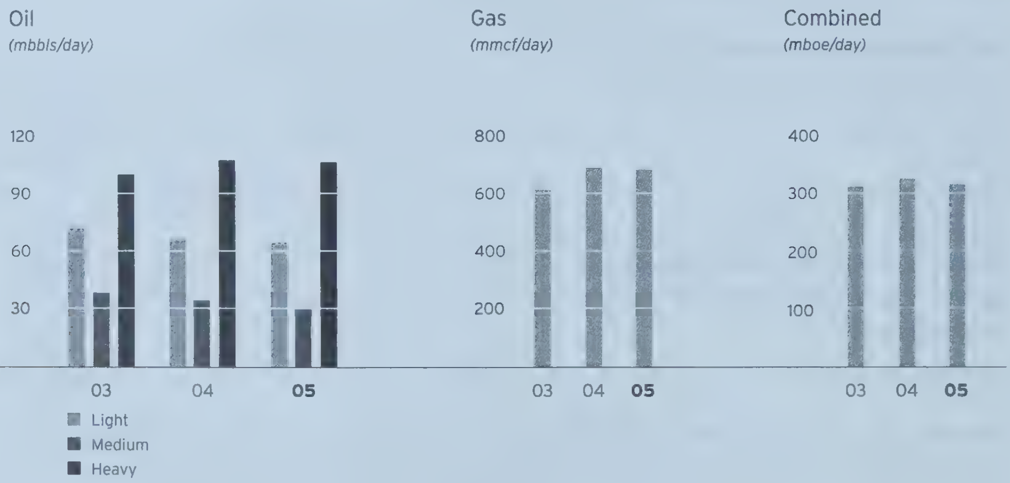
Partially offset by:

- higher royalties resulting from higher commodity prices and Terra Nova progressing to a higher royalty rate;
- lower sales volume of crude oil and natural gas, the net effect of which lowered revenue by $145 million in 2005;
- unit operating costs were $0.80/boe higher in 2005 compared with 2004 as a result of:
  - higher fuel and energy related costs;
  - increasing level of field maintenance costs involved in crude oil exploitation activities; and
  - increasing wells and compression for natural gas production.
- higher unit depletion, depreciation and amortization, which was $9.95/boe during 2005 versus $9.06 during 2004 as a result of:
  - start up of operations at the White Rose oil field offshore the East Coast of Canada; and
  - increasing exploration and exploitation costs in the Western Canada Sedimentary Basin.

Net Revenue Variance Analysis

($ millions)	Crude Oil & NGL	Natural Gas	Other	Total
Year ended December 31, 2003				
Net revenues	$ 2,097	$ 1,024	$ 65	$ 3,186
Price changes	359	98	–	457
Volume changes	(36)	172	–	136
Royalties	(67)	(60)	–	(127)
Hedging	(514)	(21)	–	(535)
Processing and sulphur	–	–	3	3
Year ended December 31, 2004				
Net revenues	1,839	1,213	68	3,120
Price changes	1,081	427	–	1,508
Volume changes	(120)	(25)	–	(145)
Royalties	(71)	(58)	–	(129)
Processing and sulphur	–	–	13	13
Year ended December 31, 2005				
Net revenues	**$ 2,729**	**$ 1,557**	**$ 81**	**$ 4,367**

Production



Daily Production, before Royalties

Year ended December 31		**2005**	2004	2003
Light crude oil & NGL	*(mbbls/day)*	**64.6**	66.2	71.6
Medium crude oil	*(mbbls/day)*	**31.1**	35.0	39.2
Heavy crude oil	*(mbbls/day)*	**106.0**	108.9	99.9
Total crude oil & NGL	*(mbbls/day)*	**201.7**	210.1	210.7
Natural gas	*(mmcf/day)*	**680.0**	689.2	610.6
Barrels of oil equivalent (6:1)	*(mboe/day)*	**315.0**	325.0	312.5

Average Sales Prices

Year ended December 31		2005	2004	2003
Crude oil	*($/bbl)*			
Light crude oil & NGL		**$ 61.56**	$ 48.34	$ 39.53
Medium crude oil		**43.44**	36.13	31.42
Heavy crude oil		**31.09**	28.66	25.87
Total average		**42.75**	36.07	31.54
Total average after hedging		**42.75**	28.43	30.93
Natural gas	*($/mcf)*			
Average		**$ 7.96**	$ 6.25	$ 5.86
Average after hedging		**7.96**	6.24	5.94

Upstream Revenue Mix (1)

Year ended December 31	2005	2004	2003
Percentage of upstream sales revenues, after royalties			
Light crude oil & NGL	**29%**	27%	29%
Medium crude oil	**9%**	11%	12%
Heavy crude oil	**24%**	27%	26%
Natural gas	**38%**	35%	33%
Total	**100%**	100%	100%

Effective Royalty Rates (1)

Year ended December 31	2005	2004	2003
Percentage of upstream sales revenues			
Light crude oil & NGL	**14%**	13%	12%
Medium crude oil	**18%**	18%	17%
Heavy crude oil	**12%**	12%	11%
Natural gas	**20%**	22%	22%
Total	**16%**	16%	16%

(1) Before commodity hedging.

Operating Netbacks

Western Canada Light Crude Oil Netbacks (1)

Year ended December 31 *(per boe)*	2005	2004	2003
Sales revenues before hedging	**$ 60.74**	$ 46.12	$ 39.91
Royalties	**8.66**	7.76	7.28
Operating costs	**9.86**	8.94	9.27
Netback	**$ 42.22**	$ 29.42	$ 23.36

Western Canada Medium Crude Oil Netbacks (1)

Year ended December 31 *(per boe)*	2005	2004	2003
Sales revenues before hedging	**$ 43.67**	$ 36.20	$ 31.57
Royalties	**7.77**	6.10	5.28
Operating costs	**10.97**	10.07	9.53
Netback	**$ 24.93**	$ 20.03	$ 16.76

(1) Includes associated co-products converted to boe.

Western Canada Heavy Crude Oil Netbacks (1)

Year ended December 31 *(per boe)*	**2005**	2004	2003
Sales revenues before hedging	**$ 31.22**	$ 28.73	$ 25.98
Royalties	**3.75**	3.38	2.76
Operating costs	**9.90**	9.33	9.09
Netback	**$ 17.57**	$ 16.02	$ 14.13

Western Canada Natural Gas Netbacks (2)

Year ended December 31 *(per mcfge)*	**2005**	2004	2003
Sales revenues before hedging	**$ 8.02**	$ 6.25	$ 5.79
Royalties	**1.76**	1.44	1.29
Operating costs	**1.04**	0.89	0.79
Netback	**$ 5.22**	$ 3.92	$ 3.71

Total Western Canada Upstream Netbacks (1)

Year ended December 31 *(per boe)*	**2005**	2004	2003
Sales revenues before hedging	**$ 42.53**	$ 35.01	$ 31.58
Royalties	**7.45**	6.22	5.48
Operating costs	**8.59**	7.85	7.56
Netback	**$ 26.49**	$ 20.94	$ 18.54

Terra Nova Crude Oil Netbacks

Year ended December 31 *(per boe)*	**2005**	2004	2003
Sales revenues before hedging	**$ 62.19**	$ 47.87	$ 38.91
Royalties	**7.95**	1.80	0.81
Operating costs	**4.53**	3.28	3.16
Netback	**$ 49.71**	$ 42.79	$ 34.94

White Rose Crude Oil Netbacks

Year ended December 31 *(per boe)*	**2005**	2004	2003
Sales revenues before hedging	**$ 63.68**	$ –	$ –
Royalties	**0.61**	–	–
Operating costs	**6.72**	–	–
Netback	**$ 56.35**	$ –	$ –

Total Canada Netbacks (1)

Year ended December 31 *(per boe)*	**2005**	2004	2003
Sales revenues before hedging	**$ 43.69**	$ 35.60	$ 32.01
Royalties	**7.36**	6.03	5.21
Operating costs	**8.39**	7.66	7.30
Netback	**$ 27.94**	$ 21.91	$ 19.50

(1) Includes associated co-products converted to boe.
(2) Includes associated co-products converted to mcfge.

Wenchang Crude Oil Netbacks

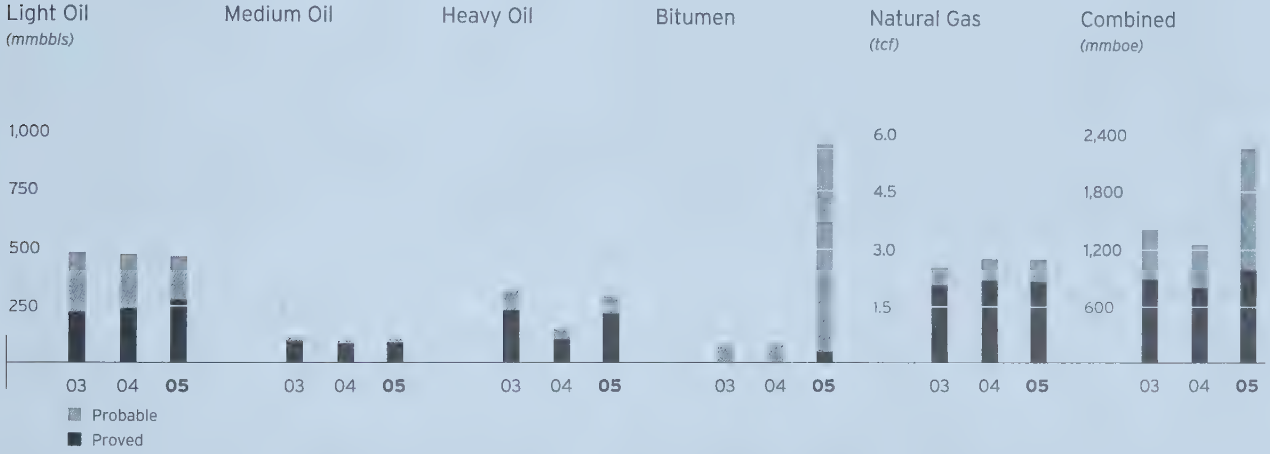
Year ended December 31 *(per boe)*	**2005**	2004	2003
Sales revenues before hedging	**$ 63.15**	$ 47.66	$ 41.45
Royalties	**5.93**	4.91	3.80
Operating costs	**2.92**	2.16	1.94
Netback	**$ 54.30**	$ 40.59	$ 35.71

Total Upstream Segment Netbacks [(1)]

Year ended December 31 *(per boe)*	**2005**	2004	2003
Sales revenues before hedging	**$ 44.56**	$ 36.34	$ 32.69
Royalties	**7.29**	5.96	5.11
Operating costs	**8.12**	7.32	6.92
Netback	**$ 29.15**	$ 23.06	$ 20.66

(1) Includes associated co-products converted to boe.

Oil and Gas Reserves



Husky applied for and was granted an exemption from Canada's National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" and provides oil and gas reserves disclosures in accordance with the United States SEC guidelines and the United States Financial Accounting Standards Board ("FASB") disclosure standards. The information disclosed may differ from information prepared in accordance with National Instrument 51-101.

For more detail on our oil and gas reserves and the disclosures with respect to the FASB's Statement No. 69, "Disclosures about Oil and Gas Producing Activities" and the differences between our disclosures and those prescribed by National Instrument 51-101, refer to our Annual Information Form available at www.sedar.com or our Form 40-F available at www.sec.gov or on our website at www.huskyenergy.ca.

At December 31, 2005, the present value of future net cash flows after tax from Husky's proved oil and gas reserves, based on prices and costs in effect at year-end and discounted at 10 percent, was $11.0 billion compared with $5.2 billion at the end of 2004.

McDaniel & Associates Consultants Ltd., an independent firm of oil and gas reserves evaluation engineers, was engaged to conduct an audit of Husky's crude oil, natural gas and natural gas products reserves. McDaniel & Associates Consultants Ltd. issued an audit opinion stating that Husky's internally generated proved and probable reserves and net present values are, in aggregate, reasonable, and have been prepared in accordance with generally accepted oil and gas engineering and evaluation practices in the United States and as set out in the Canadian Oil and Gas Evaluation Handbook.

Crude Oil and Natural Gas Reserves Summary [(1)]

(constant price before royalties)	Proved Developed			Proved Undeveloped			Total Proved			Proved and Probable		
	2005	2004	2003	**2005**	2004	2003	**2005**	2004	2003	**2005**	2004	2003
Crude oil *(mmbbls)*												
Light & NGL	**226**	191	200	**47**	47	23	**273**	238	223	**462**	465	474
Medium	**80**	80	86	**11**	6	8	**91**	86	94	**105**	96	108
Heavy	**140**	91	156	**77**	14	71	**217**	105	227	**291**	150	319
Bitumen	**–**	–	–	**48**	–	–	**48**	–	–	**951**	79	79
	446	362	442	**183**	67	102	**629**	429	544	**1,809**	790	980
Natural gas *(bcf)*	**1,710**	1,745	1,712	**426**	424	347	**2,136**	2,169	2,059	**2,709**	2,724	2,507
Total *(mmboe)*	**731**	653	727	**254**	138	160	**985**	791	887	**2,260**	1,244	1,397

(1) Refer to "Terms and Abbreviations" in this Annual Report for definitions of reserves.

2005 Reserve Additions

Our oil and gas reserves are estimated in accordance with the regulations and guidance of the SEC and the FASB which, among other things, require reserves to be evaluated using prices in effect on the day the reserves are estimated.

The additions to crude oil and NGL proved reserves from discoveries, extensions, improved recovery and technical revisions in 2005 amounted to 154 million barrels and were primarily from the White Rose oil field in the Jeanne d'Arc Basin offshore Newfoundland and Labrador, the Tucker Oil Sands project in the Cold Lake region of Alberta and the Lloydminster heavy oil region.

The additions to natural gas proved reserves from discoveries, extensions and improved recovery amounted to 286 billion cubic feet which was partially offset by net technical revisions of negative 68 billion cubic feet due to well performance. The positive results were primarily related to our drilling program in the foothills and deep basin areas of Alberta and northeastern British Columbia and the negative technical revisions were recorded at properties throughout the Western Canada Sedimentary Basin.

Reconciliation of Proved Reserves

	Canada						International		Total		
	Western Canada					East Coast					
(constant price before royalties)	Light Crude Oil & NGL *(mmbbls)*	Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Natural Gas *(bcf)*	Bitumen *(mmbbls)*	Light Crude Oil *(mmbbls)*	Light Crude Oil *(mmbbls)*	Natural Gas *(bcf)*	Crude Oil & NGL *(mmbbls)*	Natural Gas *(bcf)*	*(mmboe)*
Proved reserves at December 31, 2004	171	86	225	2,172	–	47	20	–	549	2,172	911
Heavy oil price revision	–	–	(120)	(3)	–	–	–	–	(120)	(3)	(120)
Proved reserves at December 31, 2004	171	86	105	2,169	–	47	20	–	429	2,169	791
Technical revisions	3	9	1	(68)	–	9	2	–	24	(68)	13
Heavy oil price revision	–	–	120	3	–	–	–	–	120	3	120
Purchase of reserves in place	–	–	7	3	–	–	–	–	7	3	7
Sale of reserves in place	–	(3)	(4)	(9)	–	–	–	–	(7)	(9)	(9)
Discoveries, extensions and improved recovery	5	10	27	286	48	39	1	–	130	286	178
Production	(12)	(11)	(39)	(248)	–	(6)	(6)	–	(74)	(248)	(115)
Proved reserves at December 31, 2005	**167**	**91**	**217**	**2,136**	**48**	**89**	**17**	**–**	**629**	**2,136**	**985**
Proved and probable reserves											
At December 31, 2005	**225**	**105**	**291**	**2,542**	**951**	**207**	**30**	**167**	**1,809**	**2,709**	**2,260**
At December 31, 2004	229	96	150	2,557	79	203	33	167	790	2,724	1,244

Reconciliation of Proved Developed Reserves

(constant price before royalties)	Canada – Western Canada – Light Crude Oil & NGL (mmbbls)	Medium Crude Oil (mmbbls)	Heavy Crude Oil (mmbbls)	Natural Gas (bcf)	Bitumen (mmbbls)	East Coast – Light Crude Oil (mmbbls)	Intn'l – Light Crude Oil (mmbbls)	Total – Crude Oil & NGL (mmbbls)	Natural Gas (bcf)	(mmboe)
Proved developed reserves at December 31, 2004	155	80	91	1,745	–	16	20	362	1,745	653
Revision of previous estimate	7	11	71	77	–	27	2	118	77	130
Purchase of reserves in place	–	–	2	2	–	–	–	2	2	3
Sale of reserves in place	(1)	(2)	(3)	(8)	–	–	–	(6)	(8)	(7)
Improved recovery	2	2	18	142	–	22	–	44	142	67
Production	(12)	(11)	(39)	(248)	–	(6)	(6)	(74)	(248)	(115)
Proved developed reserves at December 31, 2005	**151**	**80**	**140**	**1,710**	**–**	**59**	**16**	**446**	**1,710**	**731**

Upstream Capital Expenditures

Capital Expenditures (1)

Year ended December 31 *($ millions)*	**2005**	2004	2003
Upstream			
Exploration			
Western Canada	**$ 389**	$ 322	$ 326
East Coast Canada and Frontier	**66**	24	24
International	**55**	18	26
	510	364	376
Development			
Western Canada	**1,618**	1,211	869
East Coast Canada	**579**	515	533
International	**23**	67	–
	2,220	1,793	1,402
	$ 2,730	$ 2,157	$ 1,778

(1) *Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.*

Western Canada Drilling

Year ended December 31 *(wells)*		2005 Gross	2005 Net	2004 Gross	2004 Net	2003 Gross	2003 Net
Exploration	Oil	**89**	**85**	45	39	12	11
	Gas	**392**	**196**	234	180	147	124
	Dry	**36**	**36**	34	33	22	21
		517	**317**	313	252	181	156
Development	Oil	**466**	**433**	552	499	520	490
	Gas	**610**	**551**	807	740	540	518
	Dry	**42**	**39**	57	53	60	57
		1,118	**1,023**	1,416	1,292	1,120	1,065
Total		**1,635**	**1,340**	1,729	1,544	1,301	1,221

Canada

In 2005, upstream capital spending in Canada amounted to $2,652 million, up from $2,072 million in 2004. Capital spending in 2005 comprised $1,217 million on Western Canada conventional areas, $424 million in the Lloydminster heavy oil region, $366 million in the Alberta oil sands regions, $579 million for East Coast development and $66 million for East Coast and Northwest Territories exploration.

In 2005, spending on exploration activities comprised $213 million in the foothills and deep basin regions, $57 million in the Lloydminster heavy oil region, $24 million in the Alberta oil sands regions and $95 million in the remainder of the conventional Western Canada Sedimentary Basin.

In the Lloydminster heavy oil production region, capital spending amounted to $424 million in 2005, $57 million of which was classified as exploration. Spending in this area is primarily focused on steam-assisted gravity drainage ("SAGD"), cyclic steam and cold production techniques that are utilized to produce the 12 to 14 degree API heavy crude oil. Production of heavy crude oil is more capital intensive due to the extensive infrastructure required to produce the large amounts of steam used to heat the crude oil in-situ prior to pumping to the surface.

Exploration spending in the foothills and deep portion of the greater Western Canada Sedimentary Basin amounted to $213 million in 2005, up from $167 million in 2004. Exploration in this region, which extends along the eastern slopes of the Rocky Mountains in Alberta and into northeastern British Columbia, involves drilling deep wells into high pressure natural gas formations.

Spending on oil sands projects amounted to $366 million in 2005, up from $53 million in 2004. Our Tucker SAGD Oil Sands project is well underway and on-schedule to commence operations before the end of 2006. We spent $342 million on the Tucker project in 2005. The Sunrise Oil Sands project was approved by Alberta regulatory authorities at the end of 2005 and the front-end engineering and design is underway. During 2005 we spent $21 million on Sunrise and $3 million on other oil sands prospects.

During November 2005, the White Rose oil field in the Jeanne d'Arc Basin offshore Newfoundland and Labrador produced first oil. The project will now continue to ramp up production with the drilling of at least nine additional production and injection wells through 2006 and 2007. During 2005, exploration activities involved one exploration well at Lewis Hill in the South Whale Basin, which was abandoned without testing, and a delineation well in the White Rose field. In 2005, capital spending for exploration and development activities in this region amounted to $645 million, up from $539 million in 2004.

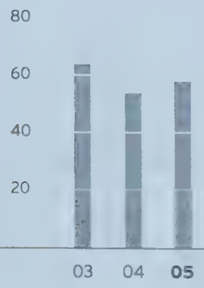
International

Exploration spending in China involved the drilling of two wells in the South China Sea. The first well encountered hydrocarbon and the results are being evaluated; the second well was plugged and abandoned without testing. In Indonesia, front-end engineering and design for the Madura Strait natural gas and NGL project is underway. Total capital spending on international activities amounted to $78 million, a similar level compared with 2004.

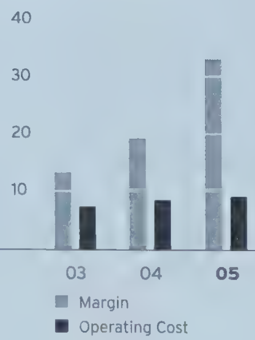
MIDSTREAM

Upgrader

Synthetic
Crude Sales
(mbbls/day)

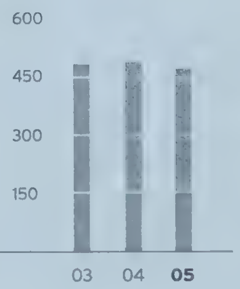


Unit Margin &
Operating Cost
($/bbl)



Pipelines

Daily
Throughput
(mbbls/day)



Upgrading Earnings Summary and 2005 Variance Analysis

Upgrading Earnings Summary

Year ended December 31 *($ millions, except where indicated)*		2005	2004	2003
Gross margin		**$ 692**	$ 383	$ 313
Operating costs		**228**	214	205
Other recoveries		**(6)**	(5)	(4)
Depreciation and amortization		**21**	19	20
Income taxes		**136**	43	21
Earnings		**$ 313**	$ 112	$ 71
Upgrader throughput (1)	*(mbbls/day)*	**66.6**	64.6	72.5
Synthetic crude oil sales	*(mbbls/day)*	**57.5**	53.7	63.6
Upgrading differential	*($/bbl)*	**$ 30.70**	$ 17.79	$ 12.88
Unit margin	*($/bbl)*	**$ 33.01**	$ 19.48	$ 13.51
Unit operating cost (2)	*($/bbl)*	**$ 9.38**	$ 9.07	$ 7.77

(1) Throughput includes diluent returned to the field.
(2) Based on throughput.

Upgrading earnings increased by $201 million in 2005 primarily due to:

- wider upgrading differential, which averaged $30.70/bbl in 2005 compared with $17.79/bbl in 2004; and
- higher sales volume of synthetic crude oil. The upgrader was down in both 2005 and 2004 for scheduled maintenance.

Partially offset by:

- higher energy and non-energy related unit operating costs.

Upgrading Earnings Variance Analysis

($ millions)	
Year ended December 31, 2003	$ 71
Volume	(48)
Differential	118
Operating costs – non-energy related	(9)
Other	1
Depreciation and amortization	1
Income taxes	(22)
Year ended December 31, 2004	112
Volume	25
Differential	284
Operating costs – energy related	(18)
Operating costs – non-energy related	5
Depreciation and amortization	(2)
Income taxes	(93)
Year ended December 31, 2005	**$ 313**

Upgrading Differential

The profitability of Husky's heavy oil upgrading operations is dependent upon the amount by which revenues from the synthetic crude oil produced exceed the costs of the heavy oil feedstock plus the related operating costs. An increase in the price of blended heavy crude oil feedstock that is not accompanied by an equivalent increase in the sales price of synthetic crude oil would reduce the profitability of our upgrading operations. We have significant crude oil production that trades at a discount to light crude oil, and any negative effect of a narrower differential on upgrading operations would be more than offset by a positive effect on revenues in the upstream segment from heavy oil production.

Infrastructure and Marketing Earnings Summary and 2005 Variance Analysis

Infrastructure and Marketing Earnings Summary

Year ended December 31 *($ millions, except where indicated)*		**2005**	2004	2003
Gross margin				
Pipeline		**$ 92**	$ 84	$ 66
Other infrastructure and marketing		**217**	136	141
		309	220	207
Other expenses		**10**	8	8
Depreciation and amortization		**21**	21	21
Income taxes		**96**	63	64
Earnings		**$ 182**	$ 128	$ 114
Aggregate pipeline throughput	*(mbbls/day)*	**474**	492	484

Infrastructure and marketing earnings increased by $54 million in 2005 primarily due to:

- higher income from oil and gas commodity marketing;
- higher heavy crude oil tariffs;
- higher Lloyd blend marketing margins;
- higher crude oil and NGL trading; and
- higher cogeneration income.

Partially offset by:

- lower heavy crude oil pipeline throughput; and
- higher operating costs due primarily to higher energy costs.

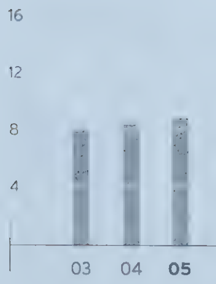
Midstream Capital Expenditures

Midstream capital expenditures of $157 million in 2005 were primarily for upgrader debottlenecking and pipeline upgrades compared with $93 million in 2004.

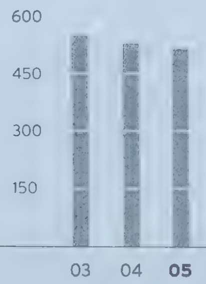
REFINED PRODUCTS

Light Oil Product Marketing

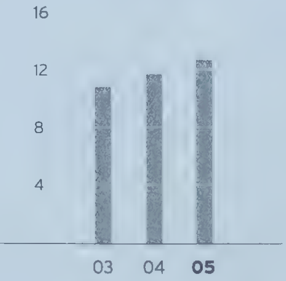
Volume
(10^6 litres/day)



Outlets

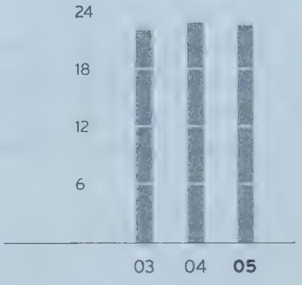


Volume per Outlet
(10^3 litres/day)



Asphalt Products

Volume
(mbbls/day)



Earnings Summary and Variance Analysis

Refined Products Earnings Summary

Year ended December 31 *($ millions, except where indicated)*		2005	2004	2003
Gross margin				
Fuel sales		**$ 126**	$ 93	$ 71
Ancillary sales		**34**	30	28
Asphalt sales		**91**	51	51
		251	174	150
Operating and other expenses		**75**	71	74
Depreciation and amortization		**47**	38	26
Income taxes		**47**	24	18
Earnings		**$ 82**	$ 41	$ 32
Number of fuel outlets		**515**	531	552
Refined products sales volume				
Light oil products	*(million litres/day)*	**8.9**	8.4	8.2
Light oil products per outlet	*(thousand litres/day)*	**12.7**	11.7	10.8
Asphalt products	*(mbbls/day)*	**22.5**	22.8	22.0
Refinery throughput				
Prince George refinery	*(mbbls/day)*	**9.7**	9.8	10.3
Lloydminster refinery	*(mbbls/day)*	**25.5**	25.3	25.7

Refined products earnings increased by $41 million in 2005 primarily due to:

- higher marketing margins and sales volume for gasoline and distillates;
- higher marketing margins of asphalt products; and
- higher restaurant and convenience store income.

Partially offset by:

- slightly lower sales volume of asphalt products; and
- higher depreciation and amortization.

Refined Products Margins

The margins realized by Husky for refined products are affected by crude oil price fluctuations, which affect refinery feedstock costs, and third-party light oil refined product purchases. Husky's ability to maintain refined products margins in an environment of higher feedstock costs is contingent upon the ability to pass on higher costs to our customers.

Integration

Husky's production of light, medium and heavy crude oil and natural gas and the efficient operation of our upgrader, refineries and other infrastructure provide opportunities to take advantage of any fluctuation in commodity prices while assisting in managing commodity price volatility. Although we are predominantly an oil and gas producer, the nature of our integrated operations is such that the upstream business segment's output provides input to the midstream and refined products segments.

Refined Products Capital Expenditures

Refined products capital expenditures in 2005 of $191 million were primarily for marketing outlet improvements, refinery upgrades and construction of an ethanol plant compared with $106 million in 2004.

CORPORATE

Corporate Earnings Summary [1]

Year ended December 31 (*$ millions*) income (expenses)	2005	2004	2003
Intersegment eliminations – net	**$ (50)**	$ (14)	$ 14
Administration expenses	**(19)**	(27)	(22)
Stock-based compensation	**(171)**	(67)	–
Accretion	**(2)**	(2)	–
Other – net	**49**	(8)	(3)
Depreciation and amortization	**(23)**	(24)	(36)
Interest on debt	**(146)**	(135)	(154)
Interest capitalized	**114**	75	52
Foreign exchange	**31**	120	282
Income taxes	**119**	94	(47)
Earnings (loss)	**$ (98)**	$ 12	$ 86

(1) 2004 and 2003 amounts as restated. Refer to Notes 3 and 11 to the Consolidated Financial Statements.

Corporate expense increased by $110 million in 2005 compared with 2004 primarily due to:

- higher intersegment profit eliminated;
- higher stock-based compensation;
- higher interest costs;
- lower foreign exchange gains on translation of U.S. dollar denominated debt; and
- provision for retrospective insurance premiums in respect of past claims on a mutual insurance consortium.

Partially offset by:

- proceeds from a litigation settlement; and
- higher capitalized interest resulting from a higher capital base for the White Rose and Tucker projects.

Foreign Exchange Summary [1]

Year ended December 31 (*$ millions*)	2005	2004	2003
(Gain) loss on translation of U.S. dollar denominated long-term debt			
Realized	**$ (13)**	$ (10)	$ 11
Unrealized	**(38)**	(140)	(393)
	(51)	(150)	(382)
Cross currency swaps			
Realized	**–**	–	32
Unrealized	**14**	27	41
	14	27	73
Other losses	**6**	3	27
	$ (31)	$ (120)	$ (282)
U.S./Canadian dollar exchange rates:			
At beginning of year	**U.S. $0.831**	U.S. $0.774	U.S. $0.633
At end of year	**U.S. $0.858**	U.S. $0.831	U.S. $0.774

(1) 2004 and 2003 amounts as restated. Refer to Notes 3 and 11 to the Consolidated Financial Statements.

Foreign Exchange Risk

Our results are affected by the exchange rate between the Canadian and U.S. dollar. The majority of our revenues are received in U.S. dollars or from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. The majority of our expenditures are in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities. In addition, a change in the value of the Canadian dollar against the U.S. dollar will result in an increase or decrease in Husky's U.S. dollar denominated debt, as expressed in Canadian dollars, as well as in the related interest expense. At December 31, 2005, 84 percent or $1.6 billion of our long-term debt was denominated in U.S. dollars. The Cdn/U.S. exchange rate at the end of 2005 was $1.1659. The percentage of our long-term debt exposed to the Cdn/U.S. exchange rate decreases to 51 percent when cross currency swaps are included. Refer to the section "Financial Risk and Risk Management."

Consolidated Income Taxes

Consolidated income taxes increased in 2005 to $809 million from $399 million in 2004 primarily as a result of higher pre-tax earnings.

In 2004, the indicative income tax rate was higher than in the previous year as a result of the 2003 amendments to the Federal and Alberta income tax acts. During 2004, the enactment of Bill 27-Alberta Corporate Tax Amendment Act, 2004 resulted in a non-recurring benefit of $40 million. During 2003, an amendment to the Federal Income Tax Act reduced the income tax rate on resource income by seven percent, provided for the deduction from income of crown royalties and eliminated the resource allowance deduction. This amendment resulted in a total benefit being recorded in 2003 of $141 million. In addition, in 2003 a non-recurring benefit totalling $20 million was recorded pursuant to Bill 41, the Alberta Corporate Tax Amendment Act, 2003. All benefits reduced future income taxes.

In 2005, current income taxes totalled $297 million and comprised $84 million in respect of the Wenchang oil field operation, $15 million of capital taxes and $198 million of Canadian income tax.

The following table shows the effect of non-recurring tax benefits for the periods noted:

($ millions)	**2005**	2004
Income taxes before tax amendments	**$ 813**	$ 439
Canadian federal and provincial tax amendments	**4**	40
Income taxes as reported	**$ 809**	$ 399

Husky's Canadian Tax Pools

Year ended December 31 *($ millions)*	**2005**	2004
Canadian exploration expense	**$ 78**	$ –
Canadian development expense	**2,033**	1,616
Canadian oil and gas property expense	**721**	557
Foreign exploration and development expense	**240**	212
Undepreciated capital costs	**4,249**	3,269
Other	**27**	22
	$ 7,348	$ 5,676

Corporate Capital Expenditures

Corporate capital expenditures of $21 million in 2005 were primarily for computer hardware and software and office furniture and equipment and compared with $23 million in 2004.

4. Liquidity and Capital Resources

SUMMARY OF CASH FLOW

Year ended December 31	2005	2004	2003
Cash flow – operating activities *($ millions)*	**$ 3,672**	$ 2,326	$ 2,509
– financing activities *($ millions)*	**$ (616)**	$ 175	$ (771)
– investing activities *($ millions)*	**$ (2,814)**	$ (2,497)	$ (2,041)
Debt to capital employed *(percent)*	**20.1**	25.8	26.9
Corporate reinvestment ratio [(1)]	**0.8**	1.1	0.9

(1) Reinvestment ratio is based on net capital expenditures including corporate acquisitions.

Cash Flow from Operating Activities

In 2005, cash generated by operating activities was $3,672 million, an increase of $1,346 million from the $2,326 million recorded in 2004. The higher cash from operating activities in 2005 was primarily due to higher earnings, partially offset by increased non-cash working capital associated with operating activities.

Cash Flow from (used for) Financing Activities

In 2005, cash used in financing activities amounted to $616 million. The cash used was composed of the repayment of long-term debt of $3,401 million and a $49 million repayment of operating lines, dividends of $700 million, including a $1.00 per share special dividend and other costs of $1 million. Cash provided by financing activities in 2005 comprised $3,235 million issuance of long-term debt, $6 million of proceeds from the exercise of stock options, proceeds from monetization of financial instruments totalling $39 million and a change of $255 million in non-cash working capital. Debt issuances and repayments include multiple drawings and repayments under revolving debt facilities.

Husky's long-term debt balances were also reduced by $51 million during 2005 primarily as a result of the narrowing of the exchange rate between Canadian and U.S. currencies.

Cash Flow used for Investing Activities

Cash used in investing activities amounted to $2,814 million in 2005, an increase of $317 million from the $2,497 million in 2004. Cash invested in 2005 was composed of capital expenditures of $3,068 million, partially offset by $74 million of proceeds from asset sales. Change in non-cash working capital and other adjustments amounted to $180 million used in investing activities.

FINANCIAL POSITION

Sources and Uses of Cash

Liquidity describes a company's ability to access cash. Companies operating in the upstream oil and gas industry require sufficient cash in order to fund capital programs necessary to maintain and increase production and proved developed reserves, to acquire strategic oil and gas assets, repay maturing debt and pay dividends. Husky's upstream capital programs are funded principally by cash provided from operating activities. During times of low oil and gas prices part of a capital program can generally be deferred. However, due to the long cycle times and the importance to future cash flow in maintaining our production, it may be necessary to utilize alternative sources of capital to continue our strategic investment plan during periods of low commodity prices. As a result, we continually examine our options with respect to sources of long and short-term capital resources. In addition, from time to time we engage in hedging a portion of our production to protect cash flow in the event of commodity price declines.

The following illustrates the Company's sources and uses of cash during the years ended December 31, 2005, 2004 and 2003:

Sources and Uses of Cash

($ millions)	**2005**	2004	2003
Cash sourced			
Cash flow from operations [(1)]	**$ 3,785**	$ 2,197	$ 2,430
Debt issue	**3,235**	2,200	669
Asset sales	**74**	36	511
Proceeds from exercise of stock options	**6**	18	51
Proceeds from monetization of financial instruments	**39**	8	44
Other	**–**	–	5
	7,139	4,459	3,710
Cash used			
Capital expenditures	**3,068**	2,349	1,868
Corporate acquisitions	**–**	102	809
Debt repayment	**3,450**	1,959	971
Special dividend on common shares	**424**	229	420
Ordinary dividends on common shares	**276**	195	160
Settlement of asset retirement obligations	**41**	40	34
Settlement of cross currency swap	**–**	–	32
Other	**32**	24	–
	7,291	4,898	4,294
Net cash (deficiency)	**(152)**	(439)	(584)
Increase (decrease) in non-cash working capital	**394**	443	281
Increase (decrease) in cash and cash equivalents	**242**	4	(303)
Cash and cash equivalents – beginning of year	**7**	3	306
Cash and cash equivalents – end of year	**$ 249**	$ 7	$ 3
Increase (decrease) in non–cash working capital			
Cash positive working capital change			
Accounts receivable decrease	**$ –**	$ 209	$ –
Inventory decrease	**–**	–	28
Prepaid expense decrease	**17**	–	–
Accounts payable and accrued liabilities increase	**984**	323	270
	1,001	532	298
Cash negative working capital change			
Accounts receivable increase	**410**	–	7
Inventory increase	**197**	77	–
Prepaid expense increase	**–**	12	10
	607	89	17
Increase (decrease) in non-cash working capital	**$ 394**	$ 443	$ 281

(1) Cash flow from operations represents net earnings plus items not affecting cash, which include accretion, depletion, depreciation and amortization, future income taxes and foreign exchange.

Capital Structure

($ millions)	December 31, 2005 Outstanding (U.S. $)	(Cdn $)	Available (Cdn $)
Short-term bank debt	$ –	$ –	$ 177
Long-term bank debt			
Syndicated credit facility	–	–	1,000
Bilateral credit facility	–	–	150
Medium-term notes	–	300	
Capital securities	225	262	
U.S. public notes	1,050	1,225	
U.S. senior secured bonds	85	99	
Total short-term and long-term debt	$ 1,360	$ 1,886	$ 1,327
Common shares and retained earnings		$ 7,520	

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2005, our working capital deficiency was $1.0 billion compared with $824 million at December 31, 2004. The increase in the deficiency is primarily due to the $1.00 per share special dividend declared on October 19, 2005 and the increase in payables for capital and commodity purchases. It is not unusual for Husky to have working capital deficits at the end of a reporting period. These working capital deficits are primarily the result of accounts payable related to capital expenditures for exploration and development. Settlement of these current liabilities is funded by cash provided by operating activities and to the extent necessary by bank borrowings. This position is a common characteristic of the oil and gas industry which, by the nature of its business, spends large amounts of capital.

As at December 31, 2005, our outstanding long-term debt totalled $1.9 billion, including amounts due within one year, compared with $2.1 billion at December 31, 2004.

At December 31, 2005, we had no drawings under our $1 billion revolving syndicated credit facility. Interest rates under this facility vary and are based on Canadian prime, Bankers' Acceptance, U.S. LIBOR or U.S. base rate, depending on the borrowing option selected and credit ratings assigned by certain rating agencies to our senior unsecured debt. The syndicated credit facility requires Husky to maintain a debt to cash flow ratio of less than three times and a consolidated tangible net worth, as of December 31, 2005, of at least $4.4 billion.

At December 31, 2005, we had no drawings under our $150 million bilateral credit facilities. The terms of these facilities are substantially the same as the syndicated credit facility.

At December 31, 2005, we had borrowed $0.4 million and utilized $18 million in support of letters of credit under our $195 million in short-term borrowing facilities. The interest rates applicable to these facilities vary and are based on Bankers' Acceptance, U.S. LIBOR or prime rates. In addition, we utilized $105 million under our dedicated letter of credit facilities.

Husky has an agreement to sell up to $350 million of net trade receivables on a revolving basis. The agreement calls for purchase discounts, based on Canadian commercial paper rates, plus a program fee to be paid on an ongoing basis. As at December 31, 2005, $350 million in outstanding accounts receivable had been sold under this agreement. The arrangement matures on January 31, 2009.

Based on our 2006 commodity price forecast, we believe that our non-cancellable contractual obligations and other commercial commitments and our 2006 capital program will be funded by cash flow from operating activities and, to the extent required, by available credit facilities. In the event of significantly lower cash flow, we would be able to defer certain of our projected capital expenditures without penalty.

We declared dividends that aggregated $1.65 per share totalling $700 million in 2005, including a special dividend of $1.00 per share. The Board of Directors of Husky has established a dividend policy that pays quarterly dividends of $0.25 ($1.00 annually) per common share. The declaration of dividends will be at the discretion of the Board of Directors, which will consider earnings, capital requirements, our financial condition and other relevant factors.

Cash and cash equivalents at December 31, 2005 totalled $249 million compared with $7 million at the beginning of the year.

On February 1, 2006, we announced the redemption of the 8.45 percent senior secured bonds amounting to U.S. $85 million.

Credit Ratings

Husky's senior debt and capital securities have been rated investment grade by several rating agencies. These ratings are disclosed and explained in detail in our Annual Information Form.

CASH REQUIREMENTS

Contractual Obligations and Other Commercial Commitments

In the normal course of business Husky is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable.

Contractual Obligations

Payments due by period (*$ millions*)	Total	2006	2007–2008	2009–2010	Thereafter
Long-term debt and interest (1)	$ 2,700	$ 403	$ 565	$ 350	$ 1,382
Operating leases	502	81	158	131	132
Firm transportation agreements	679	169	243	118	149
Unconditional purchase obligations (2)	2,017	616	1,221	171	9
Lease rentals and exploration work agreements	427	50	98	125	154
Engineering and construction commitments	531	365	166	–	–
	$ 6,856	$ 1,684	$ 2,451	$ 895	$ 1,826

(1) Includes interest on fixed rate debt.

(2) Includes purchase of refined petroleum products, processing services, distribution services, insurance premiums and natural gas purchases.

Estimated Obligations Not Included in the Table

- Asset retirement obligations

  Husky currently includes such obligations in the amortizing base of its oil and gas properties. Effective January 1, 2004 with the adoption of the Canadian Institute of Chartered Accountants ("CICA") section 3110, "Asset Retirement Obligations", Husky records a separate liability for the fair value of its asset retirement obligations. See Note 12 to the Consolidated Financial Statements.

- Employee future benefits

  Husky has a defined contribution pension plan and a post-retirement health and dental care plan for its employees. In addition, Husky has a defined benefit pension plan for approximately 200 active employees and 460 retirees and beneficiaries. In 1991, admittance to the defined benefit pension plan ended after the majority of members transferred to the newly created defined contribution pension plan. See Note 16 to the Consolidated Financial Statements.

Other Obligations

Husky is also subject to various contingent obligations that become payable only if certain events or rulings were to occur. The inherent uncertainty surrounding the timing and financial impact of these events or rulings prevents any meaningful measurement, which is necessary to assess impact on future liquidity. Such obligations include environmental contingencies, contingent consideration and potential settlements resulting from litigation.

2006 Capital Program

Husky plans to invest capital in the following segments in 2006:

Year ended December 31 (*$ millions*)	2006 Estimate
Upstream	
Western Canada	$ 1,730
East Coast Canada	350
International	140
	2,220
Midstream	340
Refined Products	260
Corporate	30
	$ 2,850

OFF-BALANCE SHEET ARRANGEMENTS

We do not utilize off-balance sheet arrangements with unconsolidated entities to enhance perceived liquidity.

Accounts Receivable Securitization Program

In the ordinary course of business, we engage in the securitization of accounts receivable. Our receivable securitization program is fully utilized at $350 million. The securitization agreement terminates on January 31, 2009. The accounts receivable are sold to an unrelated third party on a revolving basis. In accordance with the agreement, we must provide a loss reserve to replace defaulted receivables.

The securitization program provides us with cost-effective short-term funding for general corporate use. We account for these securitizations as asset sales. In the event the program is terminated, our liquidity would not be substantially reduced.

Standby Letters of Credit

In addition, from time to time, we issue letters of credit in connection with transactions in which the counterparty requires such security.

Derivative Instruments

We utilize derivative financial instruments in order to manage unacceptable risk. The derivative financial instruments currently outstanding are listed and discussed in the section "Financial Risk and Risk Management."

TRANSACTIONS WITH RELATED PARTIES AND MAJOR CUSTOMERS

Husky, in the ordinary course of business, was party to a lease agreement with Western Canadian Place Ltd. The terms of the lease provided for the lease of office space at Western Canadian Place, management services and operating costs at commercial rates. Effective July 13, 2004, Western Canadian Place Ltd. sold Western Canadian Place to an unrelated party. Western Canadian Place Ltd. is indirectly controlled by Husky's principal shareholders. Prior to the sale, we paid approximately $10 million for office space in Western Canadian Place during 2004.

We did not have any customers that constituted more than 10 percent of total sales and operating revenues during 2005.

FINANCIAL RISK AND RISK MANAGEMENT

Husky is exposed to market risks related to the volatility of commodity prices, foreign exchange rates and interest rates. Refer to Section 2. under "The Business Environment in 2005." From time to time, we use derivative instruments to manage our exposure to these risks.

Commodity Price Risk Management

Husky uses derivative commodity instruments from time to time to manage exposure to price volatility on a portion of its oil and gas production and firm commitments for the purchase or sale of crude oil and natural gas.

We implemented a corporate hedging program for 2004 to manage the volatility of natural gas and crude oil prices.

Natural Gas

As a result of a corporate acquisition, we assumed a natural gas derivative contract for a notional 7.5 mmcf/day that matured at the end of 2005. During 2005, we recorded payments totalling $17 million on this contract.

Power Consumption

During 2005, we received payments totalling $4 million on our power consumption hedges.

Foreign Currency Risk Management

At December 31, 2005, Husky had the following cross currency debt swaps in place:

- U.S. $150 million at 7.125 percent swapped at $1.45 to $218 million at 8.74 percent until November 15, 2006.
- U.S. $150 million at 6.250 percent swapped at $1.41 to $212 million at 7.41 percent until June 15, 2012.
- U.S. $75 million at 6.250 percent swapped at $1.19 to $90 million at 5.65 percent until June 15, 2012.
- U.S. $50 million at 6.250 percent swapped at $1.17 to $59 million at 5.67 percent until June 15, 2012.
- U.S. $75 million at 6.250 percent swapped at $1.17 to $88 million at 5.61 percent until June 15, 2012.

At December 31, 2005, the cost of a U.S. dollar in Canadian currency was $1.1659.

In 2005, the cross currency swaps resulted in an offset to foreign exchange gains on translation of U.S. dollar denominated debt amounting to $14 million.

In addition, we entered into U.S. dollar forward contracts, which resulted in realized gains totalling approximately $15 million in 2005. In 2004, Husky unwound its long-dated forwards resulting in a gain of $8 million, which was recognized into income during 2005 on the dates the underlying hedged transactions took place.

Interest Rate Risk Management

In 2005, interest rate risk management activities resulted in a decrease to interest expense of $13 million.

The cross currency swaps resulted in an addition to interest expense of $10 million in 2005.

We have interest rate swaps on $200 million of long-term debt, effective February 8, 2002, whereby 6.95 percent was swapped for CDOR + 175 bps until July 14, 2009. During 2005, these swaps resulted in an offset to interest expense amounting to $5 million.

In May 2005, Husky unwound the interest rate swaps on U.S. $300 million of long-term debt due June 15, 2019. Proceeds of $30 million have been deferred and are being amortized to income over the remaining term of the underlying debt. During 2005, the impact of these swaps before they were unwound was an offset to interest expense amounting to $3 million.

In November 2005, Husky unwound the interest rate swaps on U.S. $200 million of long-term debt due November 15, 2016. Proceeds of $7 million have been deferred and are being amortized to income over the remaining term of the underlying debt. During 2005, the impact of these swaps before they were unwound was an offset to interest expense amounting to $6 million.

The amortization of previous interest rate swap terminations resulted in an additional $9 million offset to interest expense in 2005.

OUTSTANDING SHARE DATA

Authorized:

- unlimited number of common shares
- unlimited number of preferred shares

Issued and outstanding: February 21, 2006

common shares	424,147,746
preferred shares	none
stock options	7,200,457
stock options exercisable	1,193,153

At February 21, 2006, 20,045,663 common shares were reserved for issuance under the stock option plan. Options awarded under the stock option plan have a maximum term of five years and vest evenly over the first three years.

5. 2006 Outlook

GENERAL ECONOMY

The factors that produced the supply and demand dynamics affecting 2004 and 2005 are expected to continue into 2006. This belief is, in part, derived from the predictions of the International Monetary Fund which forecast continued global economic growth led by the emerging Asian economies, particularly China. The world's more developed economies are not expected to interfere with this prediction. The largest consumer of petroleum, the United States, is expected to grow and Japan appears to be recovering.

General inflation is expected to continue to rise as higher petroleum costs ripple throughout the cost inputs of virtually all other products and services, including the cost of capital. Although higher petroleum prices are beneficial to creating shareholder value for oil and gas enterprises, they also impact us, since we consume vast amounts of goods and services, not the least of which is energy itself.

UPSTREAM

Production Outlook

		2006	2005 Actual
Light crude oil and NGL	*(mbbls/day)*	103 – 116	65
Medium crude oil	*(mbbls/day)*	29 – 32	31
Heavy crude oil	*(mbbls/day)*	115 – 120	106
Total crude oil and NGL	*(mbbls/day)*	247 – 268	202
Natural gas	*(mmcf/day)*	680 – 730	680
Barrels of oil equivalent (6:1)	*(mboe/day)*	360 – 390	315

Western Canada Conventional

Although the conventional production areas of the Western Canada Sedimentary Basin are considered relatively mature, current exploration and development activity is unprecedented. Production from this area is expected to account for less than 80 percent of our production in 2006, down from 90 percent in 2005 but will still be Husky's cash generating foundation. By 2010, we expect conventional production from Western Canada, including heavy oil, to account for less than 60 percent of our total production.

We expect to replace a large portion of our conventional production from development of new areas in Canada, the oil sands, basins off the East Coast and the Northwest Territories and from China and Indonesia.

Capital expenditures for development and exploration on our conventional Western Canada properties are expected to account for 66 percent of the total $2.2 billion in upstream capital expenditures in 2006; up from 60 percent in 2005. This is because of the slowing of White Rose capital spending, which was completed to first oil in 2005, and the slowing of Tucker capital spending, which will reach first oil in 2006. This represents a short dip in spending outside of the Western Canada conventional area prior to the development of the Sunrise Oil Sands and Madura natural gas and NGL projects. We expect that by 2010 capital expenditures on conventional properties in Western Canada will drop to approximately 37 percent of total upstream capital spending.

We will also continue to pursue additional natural gas reserves and production using unconventional production technology from coal beds, shale and tight formations. Based on activity in 2005, production of natural gas from coal beds is encouraging.

Oil Sands

In 2006, we will continue with and complete to first oil the development of Tucker and proceed with the front-end engineering and design of Sunrise, which will be developed in phases to reach total capacity by approximately 2012.

	Cost	Timing	Capacity
Tucker	$500 million	2006	30,000 bbls/day
Sunrise	To be finalized	2010–12	200,000 bbls/day

Canada – East Coast and Northwest Territories

On the East Coast we will continue with the development and extension of the White Rose field, including monitoring the economics and technical feasibility of natural gas developments off the East Coast, in particular the natural gas resources in the north section of the White Rose field. In addition, we will continue to identify and evaluate new prospects off the East Coast with an emphasis on the Jeanne d'Arc Basin where we recently acquired additional exploration rights on 38,600 acres, with a minimum work program commitment of $36.5 million.

In 2006, we will proceed with delineation and evaluation of the Summit Creek B-44 discovery which confirmed several productive intervals within a 180 metre zone. We and our partners hold over one million acres covering the central extent of this play.

China and Indonesia

In China, we will continue to pursue offshore prospects.

In Indonesia, we expect to conclude negotiating a natural gas sales contract and an extension to the production sharing agreement. We will continue to validate previous engineering work and make appropriate modifications during 2006. We expect that development construction will take approximately three years following project sanction.

MIDSTREAM

In 2006, we will maintain and optimize infrastructure to capitalize on increasing activity in the bitumen corridor, which extends from Lloydminster north to Fort McMurray, Alberta. We will also pursue expansion of ancillary businesses including transportation, storage, cogeneration and upgrading. In particular, we will continue the debottlenecking projects and operating performance initiatives at the Lloydminster Heavy Oil Upgrader.

REFINED PRODUCTS

In 2006, we will complete the Prince George Refinery modification, which will permit production of fuels that meet Federal requirements and we will complete the Lloydminster Ethanol Plant. We will also continue with construction of a second ethanol plant at Minnedosa, Manitoba, which will replace a small existing plant and is expected to be operational by mid-2007. We will continue to improve technology, appearance and product offerings at our marketing outlets. We will also continue to optimize the number and location of our retail outlets.

6. Application of Critical Accounting Estimates

Husky's Consolidated Financial Statements have been prepared in accordance with Canadian GAAP. The significant accounting policies we use are disclosed in Note 3 to the Consolidated Financial Statements. Certain accounting policies require that we make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The following discusses such accounting policies and is included in the MD&A to aid you in assessing the critical accounting policies and practices of Husky and the likelihood of materially different results being reported. We review our estimates regularly. The emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates.

The following assessment of significant accounting policies is not meant to be exhaustive. Husky might realize different results from the application of new accounting standards promulgated, from time to time, by various rule-making bodies.

FULL COST ACCOUNTING FOR OIL AND GAS ACTIVITIES

The indicated change in the following estimates will result in a corresponding increase in the amount of depletion, depreciation and amortization ("DD&A") expense charged to income in a given period:

An increase in:

- estimated costs to develop the proved undeveloped reserves;
- estimated fair value of the asset retirement obligation related to the oil and gas properties; and
- estimated impairment of costs excluded from the DD&A calculation.

A decrease in:

- previously estimated proved oil and gas reserves; and
- estimated proved reserves added compared to capital invested.

DEPLETION EXPENSE

Husky uses the full cost method of accounting for exploration and development activities as recommended by the CICA. In accordance with this method of accounting, all costs associated with exploration and development are capitalized on a country by country basis. The aggregate of capitalized costs, net of accumulated DD&A, plus the estimated future costs required to develop the proved undeveloped oil and gas reserves less estimated equipment salvage values is charged to income using the unit of production method based on estimated proved oil and gas reserves.

WITHHELD COSTS

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted or, if the properties are located in a cost centre where there is no reserve base, the impairment is charged directly to earnings.

FULL COST ACCOUNTING

Effective January 1, 2004, we adopted Accounting Guideline 16, "Oil and Gas Accounting – Full Cost". The new guideline modified the ceiling test, which requires, for each cost centre, capitalized costs be tested for recoverability. The test uses the estimated undiscounted future net cash flows from proved oil and gas reserves based on forecast prices and costs. When the carrying amount of a cost centre is not recoverable, the cost centre is written down to its fair value. Fair value is estimated using present value techniques which incorporate risks and other uncertainties as well as the future value of reserves when determining estimated cash flows.

IMPAIRMENT OF LONG-LIVED ASSETS

We are required to review the carrying value of all property, plant and equipment, including the carrying value of oil and gas assets, for potential impairment. Impairment is indicated if the carrying value of the long-lived asset or oil and gas cost centre is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings.

FAIR VALUE OF DERIVATIVE INSTRUMENTS

Periodically we utilize financial derivatives to manage market risk. The purpose of the derivative is to provide an element of stability to our cash flow in a volatile environment. We disclose the estimated fair value of open hedging contracts as at the end of a reporting period. Effective January 1, 2004 Husky adopted CICA Accounting Guideline 13, "Hedging Relationships" ("AcG-13"). AcG-13 has essentially the same criteria to be satisfied before the application of hedge accounting is permitted as the corresponding requirements of the FASB Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("FAS 133"). Refer to the description of FAS 133 in Note 19 to the Consolidated Financial Statements.

The estimation of the fair value of certain hedging derivatives requires considerable judgement. The estimation of the fair value of commodity price hedges requires sophisticated financial models that incorporate forward price and volatility data and which when compared with Husky's open hedging contracts, produce cash inflow or outflow variances over the contract period. The estimate of fair value for interest rate and foreign currency hedges is determined primarily through quotes from financial institutions.

Accounting rules for transactions involving derivative instruments are complex and subject to a range of interpretation. The FASB has established the Derivative Implementation Group task force, which, on an ongoing basis, considers issues arising from interpretation of these accounting rules. The potential exists that the task force may promulgate interpretations that differ from those of Husky. In this event our policy would be modified.

ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2004, we adopted the recommendations of CICA section 3110, "Asset Retirement Obligations" ("ARO"), which is essentially identical to the United States accounting requirements of FAS 143.

We have significant obligations to remove tangible assets and restore land after operations cease and we retire or relinquish the asset. The ARO relates to all of our business operations, however, approximately 90 percent of the liability relates to the upstream business. The retirement of upstream assets consists primarily of plugging and abandoning wells, removing and disposing of surface and sub-sea equipment and facilities and restoration of land to a state required by regulation or contract. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often require interpretation. Restoration technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

The new ARO rules require that an asset retirement obligation associated with the retirement of a tangible long-lived asset be recognized as a liability in the period in which a legal obligation is incurred and becomes determinable, with an offsetting increase in the carrying cost of the associated asset. The cost of the tangible asset, including the initially recognized ARO, is depleted such that the initial fair value of the ARO is recognized over the useful life of the asset. The initial fair value of the ARO is accreted to its expected settlement date. The accretion amount is expensed as a cost of operating and is added to the ARO liability. The fair value of the ARO is measured using expected future cash outflows discounted at our credit adjusted risk free interest rate.

Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, future third-party pricing, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the tangible asset balance.

LEGAL, ENVIRONMENTAL REMEDIATION AND OTHER CONTINGENT MATTERS

We are required to both determine whether a loss is probable based on judgement and interpretation of laws and regulations and determine that the loss can reasonably be estimated. When the loss is determined it is charged to earnings. The Company's management must continually monitor known and potential contingent matters and make appropriate provisions by charges to earnings when warranted by circumstances.

INCOME TAX ACCOUNTING

The determination of our income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

BUSINESS COMBINATIONS

Over recent years Husky has grown considerably through combining with other businesses. Husky acquired Temple Exploration Inc. in 2004 and Marathon Canada Limited in 2003. These transactions were accounted for using what is now the only accounting method available, the purchase method. Under the purchase method, the acquiring company includes the fair value of the assets of the acquired entity on its balance sheet. The determination of fair value necessarily involves many assumptions. The valuation of oil and gas properties primarily relies on placing a value on the oil and gas reserves. The valuation of oil and gas reserves entails the process described in Section 3. "Results of Operations — Upstream" under the caption "Oil and Gas Reserves" but in contrast incorporates the use of economic forecasts that estimate future changes in prices and costs. In addition, this methodology is used to value unproved oil and gas reserves. The valuation of these reserves, by their nature, is less certain than the valuation of proved reserves.

GOODWILL

The process of accounting for the purchase of a company, described above, results in recognizing the fair value of the acquired company's assets on the balance sheet of the acquiring company. Any excess of the purchase price over fair value is recorded as goodwill. Since goodwill results from the culmination of a process that is inherently imprecise the determination of goodwill is also imprecise. In accordance with the issuance of FASB Statement No. 142 and CICA section 3062, "Goodwill and Other Intangible Assets", goodwill is no longer amortized but assessed periodically for impairment. The process of assessing goodwill for impairment necessarily requires Husky to determine the fair value of its assets and liabilities. Such a process involves considerable judgement.

7. New Accounting Standards

LIABILITIES AND EQUITY

In November 2004, the Accounting Standards Board ("AcSB") revised recommendations in CICA section 3860, "Financial Instruments – Disclosure and Presentation", on the classification of obligations that must or could be settled with an entity's own equity instruments. The new recommendations were effective January 1, 2005 and resulted in Husky's capital securities being classified as liabilities instead of equity. The accrued return on the capital securities and the issue costs are classified outside of shareholders' equity. The return on the capital securities is a charge to earnings. The revision was applied retroactively effective January 1, 2005.

NON-MONETARY TRANSACTIONS

In June 2005, the AcSB issued CICA section 3831, "Non-monetary Transactions" which replaced section 3830 of the same name. The new recommendations require that all non-monetary transactions are measured based on fair value unless the transaction lacks commercial substance or is an exchange of product or property held for sale in the ordinary course of business. The guidance is effective for all non-monetary transactions initiated in periods beginning on or after January 1, 2006.

8. Pending Accounting Standards

In April 2005, the CICA released three new Handbook sections which deal with the recognition and measurement of financial instruments:

- Section 1530, Comprehensive Income;
- Section 3855, Financial Instruments – Recognition and Measurement; and
- Section 3865, Hedges.

The new standards are an attempt to harmonize Canadian GAAP with U.S. GAAP. Initial measurement of all financial instruments is to be based on their fair values. The subsequent measurement of the financial instrument will depend on whether it is classified as a loan or receivable; held to maturity investment; available for sale financial asset; held for trading asset or liability; or, other financial liability. Available for sale financial assets and held for trading assets or liabilities are measured at fair value on an ongoing basis. The other financial instruments are recognized at amortized cost using the effective interest method. The gains and losses on held for trading financial instruments are recognized immediately in net income. The gains and losses on available for sale financial assets will be recognized in other comprehensive income and are transferred to net income when the asset is derecognized.

Other comprehensive income is a new equity category where revenues, expenses, gains and losses are temporarily presented outside of net income but included in comprehensive income. Unrealized gains or losses on qualifying hedging instruments and available for sale financial assets are included in other comprehensive income and reclassified to net income when realized.

Hedge accounting continues to be an option and the new Handbook section provides detailed guidance on the application of hedge accounting and the required disclosures.

These new standards are effective for fiscal years beginning on or after October 1, 2006.

9. Summary of Variances for 2004 Compared with 2003

Net earnings in 2004 were $1,006 million compared with $1,370 million in 2003. The decrease of $364 million was attributable to the following:

Upstream – decrease of $354 million

- hedging losses;
- higher operating costs and DD&A;
- higher royalties; and
- higher income taxes.

Partially offset by:

- higher crude oil and natural gas prices; and
- higher sales volume of heavy crude oil and natural gas.

Midstream – increase of $55 million

- wider upgrading differential;
- higher heavy crude oil pipeline throughput and tariffs;
- higher crude oil and NGL trading; and
- higher income taxes.

Partially offset by:

- lower upgrader throughput and sales volume;
- higher unit operating costs, which were primarily energy related; and
- lower cogeneration income.

Refined Products – increase of $9 million

- higher light oil product margins; and
- higher restaurant and convenience store income.

Partially offset by:

- higher depreciation and amortization; and
- higher income taxes.

Corporate – decrease of $74 million

- lower foreign exchange gains;
- stock-based compensation first recorded in June 2004;
- higher intersegment profit eliminated; and
- higher administration expenses.

Partially offset by:

- lower depreciation and amortization;
- lower interest expense resulting from lower rates; and
- higher capitalized interest resulting from a higher capital base for the White Rose project.

10. Forward-looking Statements

This MD&A contains certain forward-looking statements relating, but not limited, to Husky's operations, anticipated financial performance, levels of production, business prospects and strategies and which are based on our expectations, estimates, projections and assumptions and were made by us in light of experience and perception of historical trends. All statements that address expectations or projections about the future, including statements about strategy for growth, expected expenditures, commodity prices, costs, production volumes and operating or financial results, are forward-looking statements. Some of our forward-looking statements may be identified by words like "expects", "anticipates", "plans", "intends", "believes", "projects", "could", "vision", "goal", "objective" and similar expressions. In addition, our production forecast and our estimate of productive capacity for White Rose, Tucker and Sunrise and plans associated with our exploration programs are forward-looking statements. Our business is subject to risks and uncertainties, some of which are similar to other energy companies and some of which are unique to Husky. Our actual results may differ materially from those expressed or implied by Husky's forward-looking statements as a result of known and unknown risks, uncertainties and other factors.

The reader is cautioned not to place undue reliance on Husky's forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, which contribute to the possibility that the predicted outcomes will not occur. The risks, uncertainties and other factors, many of which are beyond our control, that could influence actual results include, but are not limited to:

- fluctuations in commodity prices;
- the accuracy of our oil and gas reserve estimates and estimated production levels as they are affected by our success at exploration and development drilling and related activities and estimated decline rates;
- the uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures;
- changes in general economic, market and business conditions;
- fluctuations in supply and demand for our products;
- fluctuations in the cost of borrowing;
- our use of derivative financial instruments to hedge exposure to changes in commodity prices and fluctuations in interest rates and foreign currency exchange rates;
- political and economic developments, expropriations, royalty and tax increases, retroactive tax claims and changes to import and export regulations and other foreign laws and policies in the countries in which we operate;
- our ability to receive timely regulatory approvals;
- the integrity and reliability of our capital assets;
- the cumulative impact of other resource development projects;
- the maintenance of satisfactory relationships with unions, employee associations and joint venturers;
- competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternate sources of energy;
- actions by governmental authorities, including changes in environmental and other regulations that may impose restriction in areas where we operate;
- the ability and willingness of parties with whom we have material relationships to fulfill their obligations; and
- the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting us or other parties whose operations or assets directly or indirectly affect us and that may or may not be financially recoverable.

11. Oil and Gas Reserve Reporting

DISCLOSURE OF PROVED OIL AND GAS RESERVES AND OTHER OIL AND GAS INFORMATION

Husky's disclosure of proved oil and gas reserves and other information about its oil and gas activities has been made based on reliance of an exemption granted by the Canadian Securities Administrators. The exemption permits Husky to make these disclosures in accordance with requirements in the United States. These requirements and, consequently, the information presented may differ from Canadian requirements under National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities". The proved oil and gas reserves disclosed in this MD&A have been evaluated using the United States standards contained in Rule 4-10 of Regulation S-X of the Securities Exchange Act of 1934. The probable oil and gas reserves disclosed in this MD&A have been evaluated in accordance with the Canadian Oil and Gas Evaluation Handbook and National Instrument 51-101.

Husky uses the terms barrels of oil equivalent ("boe") and thousand cubic feet of gas equivalent ("mcfge"), which are calculated on an energy equivalence basis whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. Readers are cautioned that the terms boe and mcfge may be misleading, particularly if used in isolation. This measure is primarily applicable at the burner tip and does not represent value equivalence at the well head.

Cautionary note to U.S. Investors – The United States Securities and Exchange Commission permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. Husky uses certain terms in this MD&A, such as probable that the SEC's guidelines strictly prohibit from inclusion in filings with the SEC.

12. Non-GAAP Measures

DISCLOSURE OF CASH FLOW FROM OPERATIONS

This MD&A contains the term "cash flow from operations", which should not be considered an alternative to, or more meaningful than "cash flow – operating activities", as determined in accordance with GAAP as an indicator of the Company's financial performance. The Company's determination of cash flow from operations may not be comparable to that reported by other companies. Cash flow from operations equals net earnings plus items not affecting cash which include accretion, depletion, depreciation and amortization, future income taxes, foreign exchange and other non-cash items. The following table shows the reconciliation of cash flow from operations to cash flow – operating activities for the years ended December 31:

($ millions)		**2005**	2004	2003
Non-GAAP	Cash flow from operations	**$ 3,785**	$ 2,197	$ 2,430
	Settlement of asset retirement obligations	**(41)**	(40)	(34)
	Change in non-cash working capital	**(72)**	169	113
GAAP	Cash flow – operating activities	**$ 3,672**	$ 2,326	$ 2,509

13. Evaluation of Disclosure Controls and Procedures

Husky's Chief Executive Officer, acting also in his capacity as Acting Chief Financial Officer, has concluded, based on his evaluation as of a date within 90 days prior to the filing of this MD&A (the "evaluation date"), that Husky's disclosure controls and procedures are effective to ensure that information required to be disclosed by it in reports filed or submitted by it under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms, and includes controls and procedures designed to ensure that information required to be disclosed by it in such reports is accumulated and communicated to Husky's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

There have been no significant changes to Husky's disclosure controls or in other factors that could significantly affect these controls subsequent to the evaluation date and the filing date of this MD&A.

PUBLIC SECURITIES FILINGS

You may access additional information about our Company, including our Annual Information Form, which is filed with the Canadian Securities Administrators at www.sedar.com and the Form 40-F, which is filed with the United States Securities and Exchange Commission at www.sec.gov.

Management's Report

The management of Husky Energy Inc. is responsible for the financial information and operating data presented in this Annual Report.

The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise as they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. Financial information presented elsewhere in this Annual Report has been prepared on a basis consistent with that in the consolidated financial statements.

Husky Energy Inc. maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are properly accounted for and adequately safeguarded. The system of internal controls is further supported by an internal audit function.

The Audit Committee of the Board of Directors, composed of independent non-management directors, meets regularly with management, as well as the external auditors, to discuss auditing (external, internal and joint venture), internal controls, accounting policy, financial reporting matters and reserves determination process. The Committee reviews the annual consolidated financial statements with both management and the independent auditors and reports its findings to the Board of Directors before such statements are approved by the Board.

The consolidated financial statements have been audited by KPMG LLP, the independent auditors, in accordance with Canadian generally accepted auditing standards on behalf of the shareholders. KPMG LLP has full and free access to the Audit Committee.

John Lau

John C. S. Lau
President & Chief Executive Officer

Calgary, Alberta Canada
February 6, 2006

Auditors' Report to the Shareholders

We have audited the consolidated balance sheets of Husky Energy Inc., as at December 31, 2005, 2004 and 2003 and the consolidated statements of earnings, retained earnings, and cash flows for each of the years in the three-year period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005, 2004 and 2003 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2005 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Alberta Canada
February 6, 2006

Consolidated Balance Sheets

As at December 31 *(millions of dollars)*	2005	2004	2003
ASSETS			
Current assets			
Cash and cash equivalents	**$ 249**	$ 7	$ 3
Accounts receivable *(note 4)*	**856**	446	618
Inventories *(note 5)*	**471**	274	198
Prepaid expenses	**40**	52	33
	1,616	779	852
Property, plant and equipment, net *(notes 1, 6)*	**13,959**	12,193	10,862
Goodwill *(note 7)*	**160**	160	120
Other assets *(note 11)*	**62**	108	115
	$ 15,797	$ 13,240	$ 11,949
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Bank operating loans *(note 9)*	**$ –**	$ 49	$ 71
Accounts payable and accrued liabilities *(note 10)*	**2,391**	1,498	1,136
Long-term debt due within one year *(note 11)*	**274**	56	259
	2,665	1,603	1,466
Long-term debt *(note 11)*	**1,612**	2,047	1,730
Other long-term liabilities *(note 12)*	**730**	632	519
Future income taxes *(note 13)*	**3,270**	2,758	2,621
Commitments and contingencies *(note 14)*			
Shareholders' equity			
Common shares *(note 15)*	**3,523**	3,506	3,457
Retained earnings	**3,997**	2,694	2,156
	7,520	6,200	5,613
	$ 15,797	$ 13,240	$ 11,949

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2004 and 2003 amounts as restated (notes 3 and 11).

On behalf of the Board:

John C. S. Lau
Director

R.D. Fullerton
Director

Consolidated Statements of Earnings

Year ended December 31 *(millions of dollars, except per share amounts)*	**2005**	2004	2003
Sales and operating revenues, net of royalties	**$ 10,245**	$ 8,440	$ 7,658
Costs and expenses			
Cost of sales and operating expenses *(note 12)*	**5,917**	5,706	4,847
Selling and administration expenses	**138**	135	119
Stock-based compensation *(note 15)*	**171**	67	–
Depletion, depreciation and amortization *(notes 1, 6)*	**1,256**	1,179	1,021
Interest – net *(note 11)*	**32**	60	102
Foreign exchange *(note 11)*	**(31)**	(120)	(282)
Other – net	**(50)**	8	3
	7,433	7,035	5,810
Earnings before income taxes	**2,812**	1,405	1,848
Income taxes *(note 13)*			
Current	**297**	302	147
Future	**512**	97	331
	809	399	478
Net earnings	**$ 2,003**	$ 1,006	$ 1,370
Earnings per share *(note 15)*			
Basic	**$ 4.72**	$ 2.37	$ 3.26
Diluted	**$ 4.72**	$ 2.37	$ 3.25

Consolidated Statements of Retained Earnings

Year ended December 31 *(millions of dollars)*	**2005**	2004	2003
Beginning of year	**$ 2,694**	$ 2,156	$ 1,366
Net earnings	**2,003**	1,006	1,370
Dividends on common shares *(note 15)*			
Ordinary	**(276)**	(195)	(160)
Special	**(424)**	(229)	(420)
Stock-based compensation – retroactive adoption *(note 15)*	**–**	(44)	–
End of year	**$ 3,997**	$ 2,694	$ 2,156

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2004 and 2003 amounts as restated (notes 3 and 11).

Consolidated Statements of Cash Flows

Year ended December 31 *(millions of dollars)*	**2005**	2004	2003
Operating activities			
Net earnings	**$ 2,003**	$ 1,006	$ 1,370
Items not affecting cash			
Accretion *(note 12)*	**33**	27	22
Depletion, depreciation and amortization	**1,256**	1,179	1,021
Future income taxes	**512**	97	331
Foreign exchange	**(37)**	(124)	(309)
Other	**18**	12	(5)
Settlement of asset retirement obligations	**(41)**	(40)	(34)
Change in non-cash working capital *(note 8)*	**(72)**	169	113
Cash flow – operating activities	**3,672**	2,326	2,509
Financing activities			
Bank operating loans financing – net	**(49)**	(22)	71
Long-term debt issue	**3,235**	2,200	598
Long-term debt repayment	**(3,401)**	(1,937)	(971)
Settlement of cross currency swap	**–**	–	(32)
Debt issue costs	**–**	(5)	–
Proceeds from exercise of stock options	**6**	18	51
Proceeds from monetization of financial instruments	**39**	8	44
Dividends on common shares	**(700)**	(424)	(580)
Other	**(1)**	–	–
Change in non-cash working capital *(note 8)*	**255**	337	48
Cash flow – financing activities	**(616)**	175	(771)
Available for investing	**3,056**	2,501	1,738
Investing activities			
Capital expenditures	**(3,068)**	(2,349)	(1,868)
Corporate acquisitions	**–**	(102)	(809)
Asset sales	**74**	36	511
Other	**(31)**	(19)	5
Change in non-cash working capital *(note 8)*	**211**	(63)	120
Cash flow – investing activities	**(2,814)**	(2,497)	(2,041)
Increase (decrease) in cash and cash equivalents	**242**	4	(303)
Cash and cash equivalents at beginning of year	**7**	3	306
Cash and cash equivalents at end of year	**$ 249**	$ 7	$ 3

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2004 and 2003 amounts as restated (notes 3 and 11).

Except where indicated and per share amounts, all dollar amounts are in millions.

Note 1. Segmented Financial Information (1)

	Upstream			Midstream		
				Upgrading		
	2005	2004	2003	**2005**	2004	2003
Year ended December 31						
Sales and operating revenues, net of royalties	**$ 4,367**	$ 3,120	$ 3,186	**$ 1,488**	$ 1,058	$ 1,013
Costs and expenses						
Operating, cost of sales, selling and general	**1,050**	967	873	**1,018**	884	901
Depletion, depreciation and amortization	**1,144**	1,077	918	**21**	19	20
Interest – net	**–**	–	–	**–**	–	–
Foreign exchange	**–**	–	–	**–**	–	–
	2,194	2,044	1,791	**1,039**	903	921
Earnings (loss) before income taxes	**2,173**	1,076	1,395	**449**	155	92
Current income taxes	**215**	211	95	**16**	–	1
Future income taxes	**434**	152	233	**120**	43	20
Net earnings (loss)	**$ 1,524**	$ 713	$ 1,067	**$ 313**	$ 112	$ 71
Capital employed – As at December 31	**$ 8,697**	$ 7,600	$ 6,607	**$ 510**	$ 480	$ 456
Property, plant and equipment – As at December 31						
Cost						
Canada	**$18,512**	$16,023	$13,831	**$ 1,205**	$ 1,084	$ 1,023
International	**655**	587	503	**–**	–	–
	$19,167	$16,610	$14,334	**$ 1,205**	$ 1,084	$ 1,023
Accumulated depletion, depreciation and amortization						
Canada	**$ 6,729**	$ 5,722	$ 4,718	**$ 430**	$ 409	$ 391
International	**354**	311	252	**–**	–	–
	$ 7,083	$ 6,033	$ 4,970	**$ 430**	$ 409	$ 391
Net						
Canada	**$11,783**	$10,301	$ 9,113	**$ 775**	$ 675	$ 632
International	**301**	276	251	**–**	–	–
	$12,084	$10,577	$ 9,364	**$ 775**	$ 675	$ 632
Capital expenditures – Year ended December 31 (3)	**$ 2,730**	$ 2,157	$ 1,778	**$ 120**	$ 62	$ 25
Total assets – As at December 31 (4)						
Canada	**$12,559**	$10,771	$ 9,583	**$ 844**	$ 708	$ 650
International	**328**	275	264	**–**	–	–
	$12,887	$11,046	$ 9,847	**$ 844**	$ 708	$ 650

(1) 2004 and 2003 amounts as restated (notes 3 and 11).

(2) Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventories.

(3) Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.

(4) Includes goodwill on corporate acquisitions related to Upstream.

Midstream			Refined Products			Corporate and Eliminations (2)			Total		
Infrastructure and Marketing											
2005	2004	2003	2005	2004	2003	2005	2004	2003	2005	2004	2003
$ 7,383	$ 6,126	$ 4,946	**$ 2,345**	$ 1,797	$ 1,502	**$(5,338)**	$(3,661)	$(2,989)	**$10,245**	$ 8,440	$ 7,658
7,084	5,914	4,747	**2,169**	1,694	1,426	**(5,145)**	(3,543)	(2,978)	**6,176**	5,916	4,969
21	21	21	**47**	38	26	**23**	24	36	**1,256**	1,179	1,021
–	–	–	**–**	–	–	**32**	60	102	**32**	60	102
–	–	–	**–**	–	–	**(31)**	(120)	(282)	**(31)**	(120)	(282)
7,105	5,935	4,768	**2,216**	1,732	1,452	**(5,121)**	(3,579)	(3,122)	**7,433**	7,035	5,810
278	191	178	**129**	65	50	**(217)**	(82)	133	**2,812**	1,405	1,848
(14)	31	27	**(3)**	11	9	**83**	49	15	**297**	302	147
110	32	37	**50**	13	9	**(202)**	(143)	32	**512**	97	331
$ 182	$ 128	$ 114	**$ 82**	$ 41	$ 32	**$ (98)**	$ 12	$ 86	**$ 2,003**	$ 1,006	$ 1,370
$ 359	$ 402	$ 450	**$ 475**	$ 354	$ 315	**$ (635)**	$ (484)	$ (155)	**$ 9,406**	$ 8,352	$ 7,673
$ 683	$ 647	$ 622	**$ 1,063**	$ 878	$ 773	**$ 257**	$ 232	$ 205	**$21,720**	$18,864	$16,454
–	–	–	**–**	–	–	**–**	–	–	**655**	587	503
$ 683	$ 647	$ 622	**$ 1,063**	$ 878	$ 773	**$ 257**	$ 232	$ 205	**$22,375**	$19,451	$16,957
$ 247	$ 226	$ 203	**$ 476**	$ 432	$ 392	**$ 180**	$ 158	$ 139	**$ 8,062**	$ 6,947	$ 5,843
–	–	–	**–**	–	–	**–**	–	–	**354**	311	252
$ 247	$ 226	$ 203	**$ 476**	$ 432	$ 392	**$ 180**	$ 158	$ 139	**$ 8,416**	$ 7,258	$ 6,095
$ 436	$ 421	$ 419	**$ 587**	$ 446	$ 381	**$ 77**	$ 74	$ 66	**$13,658**	$11,917	$10,611
–	–	–	**–**	–	–	**–**	–	–	**301**	276	251
$ 436	$ 421	$ 419	**$ 587**	$ 446	$ 381	**$ 77**	$ 74	$ 66	**$13,959**	$12,193	$10,862
$ 37	$ 31	$ 18	**$ 191**	$ 106	$ 58	**$ 21**	$ 23	$ 23	**$ 3,099**	$ 2,379	$ 1,902
$ 866	$ 746	$ 804	**$ 834**	$ 625	$ 540	**$ 366**	$ 115	$ 108	**$15,469**	$12,965	$11,685
–	–	–	**–**	–	–	**–**	–	–	**328**	275	264
$ 866	$ 746	$ 804	**$ 834**	$ 625	$ 540	**$ 366**	$ 115	$ 108	**$15,797**	$13,240	$11,949

Note 2. Nature of Operations and Organization

Husky Energy Inc. ("Husky" or "the Company") is a publicly traded, integrated energy and energy-related company headquartered in Calgary, Alberta, Canada.

Management has segmented the Company's business based on differences in products and services and management strategy and responsibility. The Company's business is conducted predominantly through three major business segments – upstream, midstream and refined products.

Upstream includes exploration for, development and production of crude oil, natural gas and natural gas liquids. The Company's upstream operations are located primarily in Western Canada, offshore Eastern Canada, offshore China and offshore Indonesia.

Midstream includes upgrading of heavy crude oil feedstock into synthetic crude oil (upgrading); marketing of the Company's and other producers' crude oil, natural gas, natural gas liquids, sulphur and petroleum coke; and pipeline transportation and processing of heavy crude oil, storage of crude oil, diluent and natural gas and cogeneration of electrical and thermal energy (infrastructure and marketing).

Refined products include refining of crude oil and marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products.

Note 3. Significant Accounting Policies

a) Principles of Consolidation and the Preparation of Financial Statements

These financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which, in the case of the Company, differ in certain respects from those in the United States. These differences are described in note 19, Reconciliation to Accounting Principles Generally Accepted in the United States.

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. Actual results could differ from these estimates.

The consolidated financial statements include the accounts of the Company and its subsidiaries.

Substantially all of the Company's upstream activities are conducted jointly with third parties and accordingly the accounts reflect the Company's proportionate share of the assets, liabilities, revenues, expenses and cash flow from these activities.

b) Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand and deposits with a maturity of less than three months at the time of purchase.

c) Inventory Valuation

Crude oil, natural gas, refined petroleum products and purchased sulphur inventories are valued at the lower of cost or net realizable value. Cost is determined using average cost or on a first-in, first-out basis, as appropriate. Materials and supplies are valued at the lower of average cost or net realizable value. Cost consists of raw material, labour, direct overhead and transportation. Intersegment profits are eliminated.

d) Property, Plant and Equipment

i) Oil and Gas

The Company employs the full cost method of accounting for oil and gas interests whereby all costs of acquisition, exploration for and development of oil and gas reserves are capitalized and accumulated within cost centres on a country-by-country basis. Such costs include land acquisition, geological and geophysical activity, drilling of productive and non-productive wells, carrying costs directly related to unproved properties and administrative costs directly related to exploration and development activities.

The provision for depletion of oil and gas properties and depreciation of associated production facilities is calculated using the unit of production method, based on gross proved oil and gas reserves as estimated by the Company's engineers, for each cost centre. Depreciation of gas plants and certain other oil and gas facilities is provided using the straight-line method based on their estimated useful lives. Costs subject to depletion and depreciation include both the estimated costs required to develop proved undeveloped reserves and the associated addition to the asset retirement obligations. In the normal course of operations, retirements of oil and gas interests are accounted for by charging the asset cost, net of any proceeds, to accumulated depletion or depreciation. Gains or losses on the disposition of oil and gas properties are not recognized unless the gain or loss changes the depletion rate by 20 percent or more.

Costs of acquiring and evaluating significant unproved oil and gas interests are excluded from costs subject to depletion and depreciation until it is determined that proved oil and gas reserves are attributable to such interests or until impairment occurs. Costs of major development projects are excluded from costs subject to depletion and depreciation until proved developed reserves have been attributed to a portion of the property or the property is determined to be impaired.

Impairment losses are recognized when the carrying amount of a cost centre exceeds the sum of:

- the undiscounted cash flow expected to result from production from proved reserves;
- the costs of unproved properties, less impairment; and
- the costs of major development projects, less impairment.

The amount of impairment loss is determined to be the amount by which the carrying amount of the cost centre exceeds the sum of:

- the fair value of proved and probable reserves; and
- the cost, less impairment, of unproved properties and major development projects that do not have probable reserves attributed to them.

ii) Other Plant and Equipment

Depreciation for substantially all other plant and equipment, except upgrading assets, is provided using the straight-line method based on estimated useful lives of assets which range from five to 25 years. Depreciation for upgrading assets is provided using the unit of production method, based on the plant's estimated productive life. Repairs and maintenance costs, other than major turnaround costs, are charged to earnings as incurred. Major turnaround costs are deferred to other assets when incurred and amortized over the estimated period of time to the next scheduled turnaround. At the time of disposition of plant and equipment, accounts are relieved of the asset values and accumulated depreciation and any resulting gain or loss is reflected in earnings.

iii) Asset Retirement Obligations

The recognition of the fair value of obligations associated with the retirement of tangible long-lived assets is recorded in the period that the asset is put into use, with a corresponding increase to the carrying value of the related asset. The obligations recognized are legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion which is included in cost of sales and operating expenses. The liability will also be adjusted to reflect revisions to the previous estimates of the undiscounted obligation. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion, depreciation and amortization of the underlying asset. Retirement expenditures are charged to the accumulated liability as incurred.

iv) Capitalized Interest

Interest is capitalized on certain major capital projects based on the Company's long-term cost of borrowing.

e) Impairment or Disposal of Long-lived Assets

An impairment loss is recognized when the carrying value of a long-lived asset is not recoverable and exceeds its fair value. Testing for recoverability uses the undiscounted cash flows expected from the asset's use and disposition. To test for and measure impairment, long-lived assets are grouped at the lowest level for which identifiable cash flows are largely independent.

A long-lived asset that meets the conditions as held for sale is measured at the lower of its carrying amount or fair value less costs to sell. Such assets are not amortized while they are classified as held for sale. The results of operations of a component of an entity that has been disposed of, or is classified as held for sale, are reported in discontinued operations if: i) the operations and cash flows of the component have been or will be eliminated as a result of the disposal transaction; and, ii) the entity will not have a significant continuing involvement in the operations of the component after the disposal transaction.

f) Goodwill

Goodwill is the excess of the purchase price paid over the fair value of net assets acquired. Goodwill is subject to impairment tests on at least an annual basis or sooner if there are indicators of impairment. The Company tests impairment annually in the fourth quarter of each year. To assess impairment, the fair value of the reporting unit is compared with its carrying amount. If any potential impairment is indicated, then it is quantified by comparing the carrying value of goodwill to its fair value determined, based on the fair value of the assets and liabilities of the reporting unit. Impairment losses would be recognized in current period earnings.

g) Derivative Financial Instruments

Derivative financial instruments are utilized by the Company to manage market risk against the volatility in commodity prices, foreign exchange rates and interest rate exposures. The Company's policy is not to utilize derivative financial instruments for speculative purposes. The Company may choose to designate derivative financial instruments as hedges.

When applicable, at the inception of the hedge, the Company formally documents the designation of the hedge, the risk management objectives, the hedging relationships between hedged items and hedging items and the method for testing the effectiveness of the hedge which must be reasonably assured over the term of the hedge. This process includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company formally assesses, both at the inception of the hedge and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items.

The Company may enter into commodity price contracts to hedge anticipated sales of oil and natural gas production to manage its exposure to price fluctuations. Gains and losses from these contracts are recognized in upstream oil and gas revenues as the related sales occur.

The Company may enter into commodity price contracts to offset fixed price contracts entered into with customers and suppliers in order to retain market prices while meeting customer or supplier pricing requirements. Gains and losses from these contracts are recognized in midstream revenues or cost of sales as the related sales or purchases occur.

The Company may enter into interest rate swap agreements to hedge its fixed and floating interest rate mix on long-term debt. Gains and losses from these contracts are recognized as an adjustment to the interest expense on the hedged debt instrument. The related amount payable or receivable from the counterparties is recorded as an adjustment to accrued interest.

The Company may enter into foreign exchange contracts to hedge its foreign currency exposures on U.S. dollar denominated long-term debt. Gains and losses on these instruments are accrued under other current, or non-current, assets or liabilities on the balance sheet and recognized in foreign exchange in the period to which they relate, offsetting the respective foreign exchange gains and losses recognized on the underlying foreign currency long-term debt. The forward premium or discount on the foreign exchange contract is amortized as an adjustment to interest expense over the term of the contract.

The Company may enter into foreign exchange forwards and foreign exchange collars to hedge anticipated U.S. dollar denominated oil and natural gas sales. Gains and losses on these instruments are recognized as an adjustment to upstream oil and gas revenues when the sale is recorded.

Realized and unrealized gains or losses associated with derivative financial instruments which have been terminated or cease to be effective as a hedge prior to maturity are deferred under current or non-current assets or liabilities on the balance sheet and recognized into income in the period in which the underlying hedged transaction is recognized in income. In the event that a designated hedged item is sold, extinguishes or matures prior to the termination of the related derivative financial instrument, any realized or unrealized gain or loss is recognized in earnings.

h) Employee Future Benefits

The Company provides a defined contribution pension plan and a post-retirement health and dental care plan to qualified employees. The Company also maintains a defined benefit pension plan for a small number of employees who did not choose to join the defined contribution pension plan in 1991. The cost of the pension benefits earned by employees in the defined contribution pension plan is paid and expensed when incurred. The cost of the benefits earned by employees in the post-retirement health and dental care plan and defined benefit pension plan is charged to earnings as services are rendered using the projected benefit method prorated on service. The cost of the post-retirement health and dental care plan and defined benefit pension plan reflects a number of assumptions that affect the expected future benefit payments. These assumptions include, but are not limited to, attrition, mortality, the rate of return on pension plan assets and salary escalations for the defined benefit pension plan and expected health care cost trends for the post-retirement health and dental care plan. The plan assets are valued at fair value for the purposes of calculating the expected return on plan assets.

Adjustments arising out of plan amendments, changes in assumptions and experience gains and losses are normally amortized over the expected remaining average service life of the employee group.

i) Future Income Taxes

The Company follows the liability method of accounting for income taxes. Future income tax assets and liabilities are recognized at expected tax rates in effect when temporary differences between the tax basis and the carrying value of the Company's assets and liabilities reverse. The effect of a change to the tax rate on the future tax assets and liabilities is recognized in earnings when substantively enacted.

j) Non-monetary Transactions

Non-monetary transactions are measured based on fair value unless the transaction lacks commercial substance or is an exchange of product or property held for sale in the ordinary course of business.

k) Revenue Recognition

Revenues from the sale of crude oil, natural gas, natural gas liquids, synthetic crude oil, purchased commodities and refined petroleum products are recorded on a gross basis when title passes to an external party. Sales between the business segments of the Company are eliminated from sales and operating revenues and cost of sales. Revenues associated with the sale of transportation, processing and natural gas storage services are recognized when the services are provided.

l) Foreign Currency Translation

Results of foreign operations, all of which are considered financially and operationally integrated, are translated to Canadian dollars at the monthly average exchange rates for revenue and expenses, except for depreciation and depletion which are translated at the rate of exchange applicable to the related assets. Monetary assets and liabilities are translated at current exchange rates and non-monetary assets and liabilities are translated using historical rates of exchange. Gains or losses resulting from these translation adjustments are included in earnings.

m) Stock-based Compensation

Effective January 1, 2004, the Company adopted Canadian Institute of Chartered Accountants ("CICA") section 3870, "Stock-based Compensation and Other Stock-based Payments", retroactively without restatement of prior periods. In accordance with the Company's stock option plan, common share options may be granted to directors, officers and certain other employees. The recommendations require the Company to record compensation expense over the vesting period based on the fair value of options granted.

Effective June 1, 2004, the Company amended its stock option plan to a tandem plan that provides the stock option holder with the right to exercise the stock option or surrender the option for a cash payment. A liability for expected cash settlements is accrued over the vesting period of the stock options based on the difference between the exercise price of the stock options and the market price of the Company's common shares. The liability is revalued to reflect changes in the market price of the Company's common shares and the net change is recognized in earnings. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares, consideration paid by the stock option holders and the previously recognized liability associated with the stock options are recorded as share capital. Accrued compensation for an option that is forfeited is adjusted to earnings by decreasing the compensation cost in the period of forfeiture.

n) Earnings per Share

Basic common shares outstanding are the weighted average number of common shares outstanding for each period. The calculation of basic earnings per common share is based on net earnings divided by the weighted average number of common shares outstanding.

Diluted common shares outstanding are calculated using the treasury stock method, which assumes that any proceeds received from in-the-money options would be used to buy back common shares at the average market price for the period. However, since the Company has a tandem stock option plan and accrues a liability for expected cash settlements, the potential common shares issuable upon exercise associated with the stock options are not included in diluted common shares outstanding. Shares potentially issuable on the settlement of the capital securities have not been included in the determination of diluted earnings per common share, as the Company has neither the obligation nor intention to settle amounts due through the issuance of shares.

o) Reclassification

Certain prior years' amounts have been reclassified to conform with current presentation.

Note 4. Accounts Receivable

	2005	2004	2003
Trade receivables	**$ 854**	$ 448	$ 568
Investment tax credit	**–**	–	48
Allowance for doubtful accounts	**(10)**	(10)	(12)
Other	**12**	8	14
	$ 856	$ 446	$ 618

Sale of Accounts Receivable

As at December 31, 2005, the Company's ceiling on its securitization program to sell, on a revolving basis, accounts receivable to a third party was $350 million. As at December 31, 2005, $350 million (2004 – $350 million; 2003 – $250 million) in outstanding accounts receivable had been sold under the program. The agreement includes a program fee. The average effective rate for 2005 was approximately 3.0 percent (2004 – 2.6 percent; 2003 – 2.8 percent).

The Company has retained the responsibility for servicing, administering and collecting accounts receivable sold. The servicing liability at December 31, 2005 was not significant.

Proceeds from revolving sales between the third party and the Company in 2005 totalled approximately $3.4 billion (2004 – $2.5 billion).

Note 5. Inventories

	2005	2004	2003
Crude oil and refined petroleum products	**$ 241**	$ 159	$ 115
Natural gas	**207**	100	69
Materials, supplies and other	**23**	15	14
	$ 471	$ 274	$ 198

Note 6. Property, Plant and Equipment

Refer to note 1, Segmented Financial Information, which presents the Company's property, plant and equipment by segment.

General and administrative costs capitalized in 2005 were $61 million (2004 – $40 million; 2003 – $28 million).

Costs of oil and gas properties, including major development projects, excluded from costs subject to depletion and depreciation at December 31 were as follows:

	2005	2004	2003
Canada	**$ 2,317**	$ 2,399	$ 1,814
International	**127**	129	54
	$ 2,444	$ 2,528	$ 1,868

The prices used in the ceiling test evaluation of the Company's crude oil and natural gas reserves at December 31, 2005 were:

Canada	2006	2007	2008	2009	2010	Price increase 2010 to 2025 *(percent)*
Crude oil *($/bbl)*	$ 50.08	$ 46.57	$ 39.13	$ 37.12	$ 36.83	30
Natural gas *($/mcf)*	10.23	8.97	7.40	6.82	6.69	26

Note 7. Corporate Acquisitions

Effective July 15, 2004, the Company acquired all of the issued and outstanding shares of Temple Exploration Inc. ("Temple") for total cash consideration of $102 million.

Effective October 1, 2003, the Company acquired all of the issued and outstanding shares of Marathon Canada Limited and the Western Canadian assets of Marathon International Petroleum Canada, Ltd. ("Marathon Canada") for cash consideration of U.S. $611 million (Cdn $831 million).

In conjunction with the above acquisition of Marathon Canada, the Company sold certain of the Marathon Canada oil and gas properties to a third party for cash consideration of U.S. $320 million (Cdn $431 million).

The results of Temple and Marathon Canada are included in the consolidated financial statements of the Company from their acquisition dates.

The allocation of the aggregate purchase price based on the estimated fair values of the net assets of Temple and Marathon Canada on their acquisition dates was as follows:

	Temple	Marathon Canada
Net assets acquired		
Working capital (1)	$ (17)	$ (15)
Property, plant and equipment	138	1,008
Goodwill (2)	20	140
Asset retirement obligations	–	(38)
Future income taxes	(39)	(264)
	$ 102	$ 831

(1) Working capital of Marathon Canada acquired included cash of $22 million.

(2) Allocated to the Company's upstream segment and not deductible for income tax purposes. Refer to note 1, Segmented Financial Information.

Note 8. Cash Flows – Change in Non-cash Working Capital

a) Change in non-cash working capital was as follows:

	2005	2004	2003
Decrease (increase) in non-cash working capital			
Accounts receivable	**$ (410)**	$ 209	$ (7)
Inventories	**(197)**	(77)	28
Prepaid expenses	**17**	(12)	(10)
Accounts payable and accrued liabilities	**984**	323	270
Change in non-cash working capital	**394**	443	281
Relating to:			
Financing activities	**255**	337	48
Investing activities	**211**	(63)	120
Operating activities	**$ (72)**	$ 169	$ 113

b) Other cash flow information:

	2005	2004	2003
Cash taxes paid	**$ 154**	$ 213	$ 69
Cash interest paid	**$ 147**	$ 143	$ 165

Note 9. Bank Operating Loans

At December 31, 2005, the Company had unsecured short-term borrowing lines of credit with banks totalling $195 million (2004 and 2003 – $195 million). As at December 31, 2005, $0.4 million (2004 – $49 million; 2003 – $71 million) had been used for bank operating loans and $18 million (2004 – $23 million; 2003 – $18 million) had been used for letters of credit. Interest payable is based on Bankers' Acceptance, U.S. LIBOR or prime rates. During 2005, the weighted average interest rate on short-term borrowings was approximately 3.9 percent (2004 – 3.4 percent; 2003 – 3.7 percent).

Note 10. Accounts Payable and Accrued Liabilities

	2005	2004	2003
Trade payables	**$ 88**	$ 110	$ 58
Accrued liabilities	**1,247**	760	804
Dividend payable	**530**	280	42
Commodity contract settlements	**–**	50	8
Stock-based compensation	**130**	49	–
Current income taxes	**164**	119	117
Other	**232**	130	107
	$ 2,391	$ 1,498	$ 1,136

Note 11. Long-term Debt

		Cdn $ Amount			U.S. $ Denominated		
	Maturity	2005	2004	2003	2005	2004	2003
Long-term debt							
Syndicated credit facility		**$ –**	$ 70	$ –	**$ –**	$ –	$ –
Bilateral credit facilities		**–**	40	–	**–**	–	–
7.125% notes	2006	**175**	181	194	**150**	150	150
6.25% notes	2012	**467**	481	517	**400**	400	400
7.55% debentures	2016	**233**	241	258	**200**	200	200
6.15% notes	2019	**350**	361	–	**300**	300	–
Private placement notes		**–**	18	41	**–**	15	32
8.45% senior secured bonds	2006	**99**	140	188	**85**	117	145
Medium-term notes		**–**	–	200	**–**	–	–
Medium-term notes	2007	**100**	100	100	**–**	–	–
Medium-term notes	2009	**200**	200	200	**–**	–	–
8.90% capital securities	2028	**262**	271	291	**225**	225	225
Total long-term debt		**1,886**	2,103	1,989	**$ 1,360**	$ 1,407	$ 1,152
Amount due within one year		**(274)**	(56)	(259)			
		$ 1,612	$ 2,047	$ 1,730			

Interest – net for the years ended December 31 was as follows:

	2005	2004	2003
Long-term debt	$ 144	$ 133	$ 158
Short-term debt	4	3	2
	148	136	160
Amount capitalized	(114)	(75)	(52)
	34	61	108
Interest income	(2)	(1)	(6)
	$ 32	$ 60	$ 102

Foreign exchange for the years ended December 31 was as follows:

	2005	2004	2003
Gain on translation of U.S. dollar denominated long-term debt	$ (51)	$ (150)	$ (382)
Cross currency swaps	14	27	73
Other losses	6	3	27
	$ (31)	$ (120)	$ (282)

As at December 31, 2005, other assets included $21 million (2004 – $24 million; 2003 – $22 million) of deferred debt issue costs.

Credit Facilities

The revolving syndicated credit facility allows the Company to borrow up to $1 billion in either Canadian or U.S. currency from a group of banks on an unsecured basis. The facility is structured as a three-year committed revolving credit facility. Interest rates vary based on Canadian prime, Bankers' Acceptance, U.S. LIBOR or U.S. base rate, depending on the borrowing option selected and credit ratings assigned by certain credit rating agencies to the Company's rated senior unsecured debt.

The Company's $150 million revolving bilateral credit facilities have substantially the same terms as the syndicated credit facility.

Notes and Debentures

The 7.125 percent notes and the 7.55 percent debentures represent unsecured securities issued under a trust indenture dated October 31, 1996. These securities mature in 2006 and 2016, respectively. The 7.125 percent notes are not redeemable prior to maturity. Interest is payable semi-annually.

The 6.25 percent and the 6.15 percent notes represent unsecured securities issued under a trust indenture dated June 14, 2002. Interest is payable semi-annually.

On August 12, 2004, the Company filed a base shelf prospectus with securities regulatory authorities in Canada and the United States. The prospectus permits Husky to offer for sale, from time to time, up to U.S. $1 billion of debt securities during the 25-month period from August 12, 2004. No notes have been issued under the base shelf prospectus as of December 31, 2005.

The 8.45 percent senior secured bonds represent securities issued by a subsidiary under a trust indenture dated July 20, 1999. These securities amortize semi-annually. Such securities were issued in connection with the financing of the Company's share of the costs for the exploration and development of the Terra Nova oil field located off the East Coast of Canada. Interest is payable semi-annually. The Company has the option of delaying the repayment schedule by one year. The Company, through a wholly owned partnership, owns 12.51 percent of the Terra Nova oil field and associated facilities. The repayment of the securities is contracted to be made solely from revenue from the Terra Nova oil field. There is also a charge created by the partnership on its interest in the assets of the Terra Nova oil field and associated facilities in favour of the security holders. Certain related financial obligations require collateral of letters of credit and/or cash equivalents. As at December 31, 2005, letters of credit totalling $41 million (2004 and 2003 – $54 million) were outstanding. The Company redeemed these bonds in full on February 1, 2006.

The medium-term notes Series B represent unsecured securities issued under a trust indenture dated February 3, 1997 and the Series E notes represent unsecured securities issued under a trust indenture dated May 4, 1999. The amounts, rates and maturities are as follows:

Issue	Amount	Interest Rate	Maturity Date
Series B	$ 100	6.85%	February 2007
Series E	$ 200	6.95%	July 2009

Interest is payable semi-annually on all series.

The 8.90 percent capital securities represent unsecured securities under an indenture dated August 10, 1998. Such securities rank junior to all senior debt and other financial debt of the Company. The 8.90 percent interest is payable semi-annually until August 15, 2008. The capital securities mature in 2028. They are redeemable, in whole or in part, by the Company at any time prior to August 15, 2008 at a redemption price equal to the greater of the par value of the securities and the sum of the present values of the remaining scheduled payments discounted at a rate calculated using a comparable U.S. Treasury Bond rate plus an applicable spread. They are redeemable at par, in whole but not in part, by the Company on or after August 15, 2008. If not redeemed in whole, commencing on August 15, 2008, the interest rate changes to a floating rate equal to U.S. LIBOR plus 5.50 percent payable semi-annually. The Company has the right at any time prior to maturity, subject to certain conditions, to defer payment of interest for up to five years. The Company also has the unrestricted ability to settle its deferred interest, principal and redemption obligations through the issuance of common or preferred shares.

The notes and debentures disclosed above are redeemable (unless otherwise stated) at the option of the Company, at any time, at a redemption price equal to the greater of the par value of the securities and the sum of the present values of the remaining scheduled payments discounted at a rate calculated using a comparable U.S. Treasury Bond rate (for U.S. dollar denominated securities) or Government of Canada Bond rate (for Canadian dollar denominated securities) plus an applicable spread.

Capital Securities Restatement

In November 2003, the Accounting Standards Board revised recommendations in CICA section 3860, "Financial Instruments – Disclosure and Presentation", on the classification of obligations that must or could be settled with an entity's own equity instruments. The new recommendations were effective January 1, 2005 and resulted in the Company's capital securities being classified as liabilities instead of equity. The accrued return on the capital securities and the issue costs are classified outside of shareholders' equity. The return on the capital securities is a charge to earnings. The revision was applied retroactively effective January 1, 2005 and resulted in the following changes to the Company's financial statements:

	2004			2003		
	As Reported	Change	As Restated	As Reported	Change	As Restated
Consolidated Balance Sheets						
Assets						
Other assets	$ 106	$ 2	$ 108	$ 112	$ 3	$ 115
Liabilities and Shareholders' Equity						
Accounts payable and accrued liabilities	1,489	9	1,498	1,126	10	1,136
Long-term debt	1,776	271	2,047	1,439	291	1,730
Capital securities and accrued return	278	(278)	–	298	(298)	–
Consolidated Statements of Earnings						
Interest – net	$ 33	$ 27	$ 60	$ 73	$ 29	$ 102
Foreign exchange	(99)	(21)	(120)	(215)	(67)	(282)
Future income taxes	103	(6)	97	329	2	331
Net earnings	1,006	–	1,006	1,334	36	1,370

Note 12. Other Long-term Liabilities

	2005	2004	2003
Asset retirement obligations	**$ 557**	$ 509	$ 432
Cross currency swaps	**40**	68	41
Interest rate swaps	**42**	18	26
Employee future benefits	**27**	23	20
Stock-based compensation	**46**	14	–
Other	**18**	–	–
	$ 730	$ 632	$ 519

Asset Retirement Obligations

At December 31, 2005, the estimated total undiscounted inflation adjusted amount required to settle the asset retirement obligations was $3.3 billion. These obligations will be settled at the end of the useful lives of the underlying assets, which currently extend up to 50 years into the future. This amount has been discounted using credit adjusted risk free rates ranging from 6.2 percent to 6.4 percent.

Changes to the asset retirement obligations were as follows:

	2005	2004	2003
Asset retirement obligations at beginning of year	**$ 509**	$ 432	$ 286
Liabilities incurred	**63**	13	158
Liabilities disposed	**(7)**	–	–
Liabilities settled	**(41)**	(40)	(34)
Revisions	**–**	77	–
Accretion	**33**	27	22
Asset retirement obligations at end of year	**$ 557**	$ 509	$ 432

Note 13. Income Taxes

The provision for income taxes in the Consolidated Statements of Earnings reflects an effective tax rate which differs from the expected statutory tax rate. Differences for the years ended December 31 were accounted for as follows:

	2005	2004	2003
Earnings before income taxes			
Canadian	**$ 2,553**	$ 1,165	$ 1,625
Foreign jurisdictions	**259**	240	223
	2,812	1,405	1,848
Statutory income tax rate *(percent)*	**38.4**	39.3	40.2
Expected income tax	**1,080**	552	743
Effect on income tax of:			
Royalties, lease rentals and mineral taxes payable to the crown	**105**	153	175
Resource allowance on Canadian production income	**(133)**	(156)	(183)
Rate benefit on partnership earnings	**(69)**	(42)	(23)
Change in statutory tax rate	**(4)**	(40)	(161)
Non-deductible capital taxes	**15**	20	22
Capital gains and losses	**(140)**	(23)	(58)
Foreign jurisdictions	**(14)**	(13)	(16)
Other – net	**(31)**	(52)	(21)
Income tax expense	**$ 809**	$ 399	$ 478

The future income tax liability at December 31 comprised the tax effect of temporary differences as follows:

	2005	2004	2003
Future tax liabilities			
Property, plant and equipment	**$ 3,487**	$ 2,949	$ 2,826
Foreign exchange gains taxable on realization	**60**	56	32
Other temporary differences	**2**	5	2
	3,549	3,010	2,860
Future tax assets			
Asset retirement obligations	**195**	180	160
Loss carry forwards	**–**	11	2
Provincial royalty rebates	**7**	14	52
Other temporary differences	**77**	47	25
	279	252	239
	$ 3,270	$ 2,758	$ 2,621

Note 14. Commitments and Contingencies

Certain former owners of interests in the upgrading assets retained a 20-year upside financial interest expiring in 2014 which requires payments to them when the average differential between heavy crude oil feedstock and synthetic crude oil exceeds $6.50 per barrel. The calculation is based on a two-year rolling average of the differential. During 2005, the Company capitalized $68 million (2004 – $27 million; 2003 – $10 million) of payments under this arrangement.

At December 31, 2005, the Company had commitments for non-cancellable operating leases and other long-term agreements that require the following minimum future payments:

	2006	2007	2008	2009	2010	After 2010	Total
Operating leases	$ 81	$ 82	$ 76	$ 68	$ 63	$ 132	$ 502
Firm transportation agreements	169	133	110	68	50	149	679
Unconditional purchase obligations	616	656	565	127	44	9	2,017
Lease rentals and exploration work agreements	50	54	44	44	81	154	427
Engineering and construction commitments	365	154	12	–	–	–	531
	$ 1,281	$ 1,079	$ 807	$ 307	$ 238	$ 444	$ 4,156

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favour, the Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these and other matters or any amount which it may be required to pay by reason thereof would have a material adverse impact on its financial position, results of operations or liquidity. In 2005 a lawsuit was settled with proceeds received and the resulting gain was recognized in earnings and recorded in other – net.

The Company has income tax filings that are subject to audit and potential reassessment. The findings may impact the tax liability of the Company. The final results are not reasonably determinable at this time and management believes that it has adequately provided for current and future income taxes.

Note 15. Share Capital

The Company's authorized share capital is as follows:

Common shares – an unlimited number of no par value.

Preferred shares – an unlimited number of no par value, none outstanding.

Common Shares

Changes to issued share capital were as follows:

	Number of Shares	Amount
December 31, 2002	417,873,601	$ 3,406
Options and warrants exercised	4,302,141	51
December 31, 2003	422,175,742	3,457
Stock-based compensation – adoption	–	23
Options and warrants exercised	1,560,672	26
December 31, 2004	423,736,414	3,506
Options and warrants exercised	388,664	17
December 31, 2005	**424,125,078**	**$ 3,523**

Stock Options

At December 31, 2005, 20.4 million common shares were reserved for issuance under the Company stock option plan. As described in note 3 m), on June 1, 2004, the Company modified its stock option plan to a tandem plan that provides the stock option holder with the right to exercise the option or surrender the option for a cash payment. The exercise price of the option is equal to the average market price of the Company's common shares during the five trading days prior to the date of the award. When the option is surrendered for cash, the cash payment is the difference between the average market price of the Company's common shares on the trading day prior to the surrender date and the exercise price of the option. Under the stock option plan the options awarded have a maximum term of five years and vest over three years on the basis of one-third per year.

A downward adjustment of $0.55 was made to the exercise price of all outstanding stock options effective December 1, 2005, pursuant to the terms of the stock option plan under which the options were issued as a result of the special $1.00 per share dividend that was declared in November 2005. Similar downward adjustments of $0.48 in 2004 and $0.82 in 2003 were made to the exercise price of all outstanding stock options as a result of a special dividend declared in each of those years.

The following options to purchase common shares have been awarded to directors, officers and certain other employees:

	Number of Options *(thousands)*	Weighted Average Exercise Prices	Weighted Average Contractual Life *(years)*	Options Exercisable *(thousands)*
December 31, 2002	7,920	$ 13.91	3	4,822
Granted	591	$ 19.17	5	
Exercised for common shares	(3,789)	$ 13.45	2	
Forfeited	(125)	$ 14.71	2	
December 31, 2003	4,597	$ 13.88	2	3,564
Granted	8,200	$ 25.10	4	
Exercised for common shares	(1,350)	$ 13.11	1	
Surrendered for cash	(1,269)	$ 13.32	1	
Forfeited	(214)	$ 22.73	4	
December 31, 2004	9,964	$ 22.61	4	1,417
Granted	670	$ 48.14	5	
Exercised for common shares	(359)	$ 15.84	1	
Surrendered for cash	(2,443)	$ 19.05	2	
Forfeited	(547)	$ 24.10	3	
December 31, 2005	**7,285**	**$ 25.81**	**3**	**1,533**

As at December 31, 2005	Outstanding Options			Options Exercisable	
Range of Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Prices	Weighted Average Contractual Life *(years)*	Number of Options *(thousands)*	Weighted Average Exercise Prices
$13.67 – $14.99	187	$ 14.32	2	144	$ 14.17
$15.00 – $22.99	234	$ 19.44	3	116	$ 19.98
$23.00 – $23.99	5,977	$ 23.83	3	1,252	$ 23.83
$24.00 – $39.99	392	$ 32.11	4	21	$ 30.60
$40.00 – $55.14	495	$ 52.12	5	–	$ –
	7,285	**$ 25.81**	**3**	**1,533**	**$ 22.72**

Warrants

In 2000, the Company granted 1.4 million Renaissance Energy Ltd. ("Renaissance") replacement options to purchase common shares of Husky in exchange for certain share purchase options to purchase common shares of Renaissance previously held by employees of Renaissance. The former shareholders of Husky Oil Limited were also granted warrants to acquire, for no additional consideration, 1.86 common shares of the Company for each common share issued on the exercise of a Renaissance replacement option. During 2005, 16,000 warrants were exercised (2004 – 113,600; 2003 – 276,500). As at December 31, 2005, there were no Renaissance replacement options or warrants outstanding.

Earnings per Common Share

	2005	2004	2003
Net earnings	**$ 2,003**	$ 1,006	$ 1,370
Weighted average number of common shares outstanding			
Basic *(millions)*	**424.0**	423.4	419.5
Effect of dilutive stock options and warrants	**–**	0.9	2.0
Weighted average number of common shares outstanding			
Diluted *(millions)*	**424.0**	424.3	421.5
Earnings per share			
Basic	**$ 4.72**	$ 2.37	$ 3.26
Diluted	**$ 4.72**	$ 2.37	$ 3.25

Stock-based Compensation

As described in note 3 m), beginning January 1, 2004, stock-based compensation is being recognized in earnings. This change was adopted retroactively without restatement of prior periods and resulted in a decrease to retained earnings of $44 million, an increase to contributed surplus of $21 million and an increase to share capital of $23 million on January 1, 2004. If the Company had applied the fair value method retroactively with restatement of prior periods for all options granted, the Company's net earnings and earnings per share for the year ended December 31, 2003 would have been as follows:

	2003
Compensation cost – all options granted (1)	$ 14
Net earnings available to common shareholders	
As reported	$ 1,370
As restated	$ 1,356
Weighted average number of common shares outstanding *(millions)*	
Basic	419.5
Diluted	421.5
Basic earnings per share	
As reported	$ 3.26
As restated	$ 3.23
Diluted earnings per share	
As reported	$ 3.25
As restated	$ 3.22

(1) Includes options modified.

As described in note 3 m), effective June 1, 2004, the Company modified the stock option plan to a tandem plan. Prior to the modification, the fair values of all common share options granted were estimated on the date of grant using the Black-Scholes option-pricing model. The grant date fair values and assumptions used prior to June 1, 2004 were:

	2004	2003
Weighted average fair value per option	$ 5.67	$ 4.00
Risk-free interest rate *(percent)*	3.1	3.9
Volatility *(percent)*	21	23
Expected life *(years)*	5	5
Expected annual dividend per share	$ 0.44	$ 0.36

As a result of the downward adjustment of $0.82 to the exercise price of all outstanding options effective September 3, 2003, the fair values of all common share options granted prior to that date were revalued on September 3, 2003 using the Black-Scholes option-pricing model. The weighted average fair value of outstanding stock options as at September 3, 2003 and the assumptions used are noted below:

Weighted average fair value per option	$ 7.14
Risk-free interest rate *(percent)*	2.8
Volatility *(percent)*	20
Expected life *(years)*	2.3
Expected annual dividend per share	$ 0.40

Dividends

During 2005, the Company declared dividends of $1.65 per common share (2004 – $1.00 per common share; 2003 – $1.38 per common share), including a special dividend of $1.00 per common share (2004 – $0.54 per common share; 2003 – $1.00 per common share).

Contributed Surplus

Changes to contributed surplus were as follows:

	2004
December 31, 2003	$ –
Stock-based compensation – adoption	21
Stock-based compensation cost	1
Stock options exercised	(6)
Modification of stock option plan – June 1, 2004	(16)
December 31, 2004	$ –

Note 16. Employee Future Benefits

The Company currently provides a defined contribution pension plan for all qualified employees. The Company also maintains a defined benefit pension plan, which is closed to new entrants, and all current participants are vested. The Company also provides certain health and dental coverage to its retirees which is accrued over the expected average remaining service life of the employees.

Weighted average long-term assumptions are based on independent historical and projected references and are noted below:

	2005	2004	2003
Discount rate *(percent)*	**5.8**	6.0	6.0
Long-term rate of increase in compensation levels *(percent)*	**5.0**	5.0	5.0
Long-term rate of return on plan assets *(percent)*	**7.5**	8.0	8.0

The discount rate used at the end of 2005 to determine the accrued benefit obligation was 5.0 percent.

The long-term rate of return on the assets was determined based on management's best estimate and the historical rates of return, adjusted periodically. The rate at the end of 2005 was 7.5 percent.

The average health care cost trend used was eight percent, which is reduced by 0.50 percent until 2009. The average dental care cost trend used was four percent, which remains constant.

Defined Benefit Pension Plan

The status of the defined benefit pension plan at December 31 was as follows:

Benefit Obligation	**2005**	2004	2003
Benefit obligation, beginning of year	**$ 124**	$ 118	$ 108
Current service cost	**2**	2	2
Interest cost	**7**	7	7
Benefits paid	**(6)**	(6)	(6)
Actuarial losses	**11**	3	7
Benefit obligation, end of year	**$ 138**	$ 124	$ 118

Fair Value of Plan Assets

	2005	2004	2003
Fair value of plan assets, beginning of year	**$ 96**	$ 85	$ 77
Contributions	**11**	10	8
Benefits paid	**(6)**	(6)	(6)
Expected return on plan assets	**7**	7	6
Gain on plan assets	**–**	1	2
Foreign exchange losses	**–**	(1)	(2)
Fair value of plan assets, end of year	**$ 108**	$ 96	$ 85

Funded Status of Plan

	2005	2004	2003
Fair value of plan assets	**$ 108**	$ 96	$ 85
Benefit obligation	**(138)**	(124)	(118)
Excess obligation	**(30)**	(28)	(33)
Unrecognized past service costs	**1**	1	1
Unrecognized losses	**40**	32	32
Accrued benefit asset	**$ 11**	$ 5	$ –

Husky adheres to a Statement of Investment Policies and Procedures (the "Policy"). The assets are allocated in accordance with the long-term nature of the obligation and comprise a balanced investment based on interest rate and inflation sensitivities. The Policy explicitly prescribes diversification parameters for all classes of investment.

The date of the last actuarial valuation for the Company was January 1, 2005.

The composition of the defined benefit pension plan assets was as follows:

	2005	2004	2003
U.S. common equities	**–%**	15%	15%
Canadian common equities	**29**	25	28
International equity mutual funds	**28**	11	10
Canadian equity mutual funds	**–**	–	2
Canadian government bonds	**18**	25	29
Canadian corporate bonds	**3**	16	12
Canadian fixed income mutual funds	**20**	–	–
Cash and receivables	**2**	8	4
Total	**100%**	100%	100%

During 2005, Husky contributed $11 million to the defined benefit pension plan assets, $9 million of which was in respect of additional contributions as a result of the plan's deficiency. Husky currently plans to contribute $10 million in 2006.

The Company amortizes the portion of the unrecognized actuarial gains or losses that exceed 10 percent of the greater of the accrued benefit obligation or the market-related value of pension plan assets. The market-related value of pension plan assets is the fair value of the assets. The gains or losses that are in excess of 10 percent are amortized over the expected future years of service, which is currently seven years.

The past service costs are amortized over the expected future years of service.

Post-retirement Health and Dental Care Plan

The status of the post-retirement health and dental care plan at December 31 was as follows:

Benefit Obligation	2005	2004	2003
Benefit obligation, beginning of year	$ 25	$ 23	$ 21
Current service cost	2	2	2
Interest cost	1	1	1
Benefits paid	–	(1)	(1)
Actuarial losses	5	–	–
Benefit obligation, end of year	$ 33	$ 25	$ 23

Funded Status of Plan	2005	2004	2003
Benefit obligation	$ (33)	$ (25)	$ (23)
Unrecognized losses	6	2	3
Accrued benefit liability	$ (27)	$ (23)	$ (20)

The assumed health care cost trend can have a significant effect on the amounts reported for Husky's post-retirement health and dental care plan. A one percent increase and decrease in the assumed trend rate would have the following effect:

	1% Increase	1% Decrease
Effect on total service and interest cost components	$ 1	$ –
Effect on post-retirement benefit obligation	$ 6	$ (5)

Pension Expense and Post-retirement Health and Dental Care Expense

The expenses for the years ended December 31 were as follows:

Pension Expense	2005	2004	2003
Defined benefit pension plan			
Employer current service cost	$ 2	$ 2	$ 2
Interest cost	7	7	7
Expected return on plan assets	(7)	(7)	(6)
Amortization of net actuarial losses	3	2	2
	5	4	5
Defined contribution pension plan	14	12	11
Total expense	$ 19	$ 16	$ 16

Post-retirement Health and Dental Care Expense	2005	2004	2003
Employer current service cost	$ 2	$ 2	$ 2
Interest cost	1	1	1
Total expense	$ 3	$ 3	$ 3

Future Benefit Payments

The following table discloses the current estimate of future benefit payments:

	Defined Benefit Pension Plan	Post-retirement Health and Dental Care Plan
2006	$ 7	$ 1
2007	7	1
2008	8	1
2009	8	1
2010	8	1
2011 – 2015	46	7

Note 17. Related Party Transactions

Husky, in the ordinary course of business, was party to a lease agreement with Western Canadian Place Ltd. The terms of the lease provided for the lease of office space at Western Canadian Place, management services and operating costs at commercial rates. Effective July 13, 2004, Western Canadian Place Ltd. sold Western Canadian Place to an unrelated party. Western Canadian Place Ltd. is indirectly controlled by Husky's principal shareholders. Prior to the sale, Husky paid approximately $10 million for office space in Western Canadian Place during 2004 (2003 – $17 million).

Note 18. Financial Instruments and Risk Management

Carrying Values and Estimated Fair Values of Financial Assets and Liabilities

The carrying value of cash and cash equivalents, accounts receivable, bank operating loans, accounts payable and accrued liabilities approximates their fair value due to the short-term maturity of these instruments.

The fair value of the long-term debt is the present value of future cash flows associated with the debt. Market information such as treasury rates and credit spreads is used to determine the appropriate discount rates. The estimated fair value of the long-term debt at December 31 was as follows:

	2005		2004		2003	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	**$ 1,886**	**$ 1,995**	$ 2,103	$ 2,296	$ 1,989	$ 2,209

Unrecognized Gains (Losses) on Derivative Instruments

	2005	2004	2003
Commodity price risk management			
Natural gas	**$ –**	$ (9)	$ (8)
Crude oil	**–**	–	(109)
Power consumption	**–**	(1)	2
Interest rate risk management			
Interest rate swaps	**7**	52	31
Foreign currency risk management			
Foreign exchange contracts	**(32)**	(30)	(19)
Foreign exchange forwards	**–**	–	15

Commodity Price Risk Management

Natural Gas Production

During 2005 the impact of hedging was a loss of $17 million (2004 – loss of $1 million; 2003 – gain of $16 million).

Crude Oil Production

The Company did not have a hedge program in 2005. The impact of hedging in 2004 and 2003 was a loss of $560 million and $36 million, respectively.

Power Consumption

The impact of the 2005 hedge program was a gain of $4 million (2004 – gain of $3 million).

Natural Gas Contracts

The Company has a portfolio of fixed and basis price offsetting physical forward purchase and sale natural gas contracts relating to marketing of other producers' natural gas. The objective of these contracts is to "lock in" a positive spread between the physical purchase and sale contract prices. At December 31, 2005, the Company had the following offsetting physical purchase and sale contracts:

	Volumes *(mmcf)*	Unrecognized Gain (Loss)
Physical purchase contracts	35,261	$ 29
Physical sale contracts	(35,261)	$ (28)

Interest Rate Risk Management

The majority of the Company's long-term debt has fixed interest rates and various maturities. The Company periodically uses interest rate swaps to manage its financing costs. At December 31, 2005, the Company had entered into interest rate swap arrangements whereby the fixed interest rate coupon on certain debt was swapped to floating rates with the following terms:

Debt	Amount	Swap Maturity	Swap Rate *(percent)*
6.95% medium-term notes	$200	July 14, 2009	CDOR + 175 bps

During 2005 the Company realized a gain of $13 million (2004 – gain of $22 million; 2003 – gain of $17 million) from interest rate risk management activities.

In 2005 and 2003, the Company unwound interest rate swaps for proceeds of $37 million and $44 million, respectively. The proceeds have been deferred and are being amortized to income over the remaining term of the underlying debt.

Foreign Currency Risk Management

The Company manages its exposure to foreign exchange rate fluctuations by balancing the U.S. dollar denominated cash flows with U.S. dollar denominated borrowings and other financial instruments. Husky utilizes spot and forward sales to convert cash flows to or from U.S. or Canadian currency.

At December 31, 2005, the Company had the following cross currency debt swaps:

Debt	Swap Amount	Canadian Equivalent	Swap Maturity	Interest Rate *(percent)*
7.125% notes	U.S. $150	$218	November 15, 2006	8.74
6.25% notes	U.S. $150	$212	June 15, 2012	7.41
6.25% notes	U.S. $ 75	$ 90	June 15, 2012	5.65
6.25% notes	U.S. $ 50	$ 59	June 15, 2012	5.67
6.25% notes	U.S. $ 75	$ 88	June 15, 2012	5.61

The Company hedged U.S. dollar revenues for various amounts and maturities through 2005 using foreign exchange forwards. On November 10, 2004, the Company unwound its long-dated forwards, which resulted in a gain of $8 million that was deferred and was recognized into income during 2005 on the dates that the underlying hedged transactions took place.

During 2005 the Company recognized a gain of $1 million (2004 – loss of $13 million; 2003 – loss of $56 million) from foreign currency risk management activities.

Credit Risk

Accounts receivable are predominantly with customers in the energy industry and are subject to normal industry credit risks.

In addition, the Company is exposed to credit related losses in the event of non-performance by counterparties to its derivative financial instruments. The Company's policy is to primarily deal with major financial institutions and investment grade rated entities to mitigate these risks.

Husky did not have any customers that constituted more than 10 percent of total sales and operating revenues during 2005.

Note 19. Reconciliation to Accounting Principles Generally Accepted in the United States

The Company's consolidated financial statements have been prepared in accordance with GAAP in Canada, which differ in some respects from those in the United States. Any differences in accounting principles as they pertain to the accompanying consolidated financial statements were insignificant except as described below:

Consolidated Statements of Earnings	**2005**	2004	2003
Net earnings under Canadian GAAP [(1)]	**$ 2,003**	$ 1,006	$ 1,370
Adjustments:			
Full cost accounting [(a)]	**66**	37	80
Related income taxes	**(23)**	(13)	(29)
Derivatives and hedging [(b)]	**–**	–	(1)
Related income taxes	**–**	–	1
Energy trading contracts [(c)]	**–**	(1)	(15)
Related income taxes	**–**	–	6
Stock-based compensation [(e)]	**–**	2	(46)
Earnings before cumulative effect of change in accounting principle under U.S. GAAP	**2,046**	1,031	1,366
Cumulative effect of change in accounting principle, net of tax [(d)]	**–**	–	9
Net earnings under U.S. GAAP	**$ 2,046**	$ 1,031	$ 1,375
Weighted average number of common shares outstanding under U.S. GAAP *(millions)*			
Basic	**424.0**	423.4	419.5
Diluted	**424.0**	424.3	421.5
Earnings per share before cumulative effect of change in accounting principle under U.S. GAAP			
Basic	**$ 4.83**	$ 2.44	$ 3.26
Diluted	**$ 4.83**	$ 2.43	$ 3.24
Earnings per share under U.S. GAAP			
Basic	**$ 4.83**	$ 2.44	$ 3.28
Diluted	**$ 4.83**	$ 2.43	$ 3.26

(1) 2004 and 2003 amounts as restated (notes 3 and 11).

Condensed Consolidated Balance Sheets	2005		2004		2003	
	Canadian GAAP	**U.S. GAAP**	Canadian GAAP [1]	U.S. GAAP	Canadian GAAP [1]	U.S. GAAP
Current assets [b] [c]	**$ 1,616**	**$ 1,672**	$ 779	$ 837	$ 852	$ 911
Property, plant and equipment, net [a]	**13,959**	**13,465**	12,193	11,633	10,862	10,264
Other assets [i]	**222**	**223**	268	269	235	236
	$15,797	**$15,360**	$13,240	$12,739	$11,949	$11,411
Current liabilities [b] [c] [i]	**$ 2,665**	**$ 2,766**	$ 1,603	$ 1,656	$ 1,466	$ 1,628
Long-term debt [b]	**1,612**	**1,670**	2,047	2,124	1,730	1,794
Other long-term liabilities [b]	**730**	**688**	632	614	519	493
Future income taxes [a] [b] [c] [d] [i]	**3,270**	**3,089**	2,758	2,555	2,621	2,372
Share capital [e] [f] [g]	**3,523**	**3,757**	3,506	3,740	3,457	3,737
Retained earnings	**3,997**	**3,431**	2,694	2,085	2,156	1,478
Accumulated other comprehensive income						
Cash flow hedges, net of tax [b]	**–**	**(21)**	–	(20)	–	(76)
Minimum pension liability, net of tax [i]	**–**	**(20)**	–	(15)	–	(15)
	$15,797	**$15,360**	$13,240	$12,739	$11,949	$11,411

Condensed Consolidated Statements of Retained Earnings and Accumulated Other Comprehensive Income	2005		2004		2003	
	Canadian GAAP	**U.S. GAAP**	Canadian GAAP [1]	U.S. GAAP	Canadian GAAP [1]	U.S. GAAP
Retained earnings, beginning of year	**$ 2,694**	**$ 2,085**	$ 2,156	$ 1,478	$ 1,366	$ 683
Net earnings	**2,003**	**2,046**	1,006	1,031	1,370	1,375
Dividends on common shares	**(700)**	**(700)**	(424)	(424)	(580)	(580)
Stock-based compensation – retroactive adoption [e]	**–**	**–**	(44)	–	–	–
Retained earnings, end of year	**$ 3,997**	**$ 3,431**	$ 2,694	$ 2,085	$ 2,156	$ 1,478
Accumulated other comprehensive income, beginning of year	**$ –**	**$ (35)**	$ –	$ (91)	$ –	$ (17)
Cash flow hedges, net of tax [b]	**–**	**(1)**	–	56	–	(69)
Minimum pension liability, net of tax [i]	**–**	**(5)**	–	–	–	(5)
Accumulated other comprehensive income, end of year	**$ –**	**$ (41)**	$ –	$ (35)	$ –	$ (91)

(1) 2004 and 2003 amounts as restated (notes 3 and 11).

Condensed Consolidated Statements of Earnings and Comprehensive Income	2005		2004		2003	
	Canadian GAAP	**U.S. GAAP**	Canadian GAAP (1)	U.S. GAAP	Canadian GAAP (1)	U.S. GAAP
Sales and operating revenues (b) (c) (h)	**$10,245**	**$ 8,445**	$ 8,440	$ 7,038	$ 7,658	$ 6,823
Costs and expenses (b) (c) (e) (h)	**6,112**	**4,312**	5,769	4,366	4,665	3,892
Accretion expense	**33**	**33**	27	27	22	22
Depletion, depreciation and amortization (a)	**1,256**	**1,190**	1,179	1,142	1,021	941
Interest – net	**32**	**32**	60	60	102	102
Earnings before income taxes	**2,812**	**2,878**	1,405	1,443	1,848	1,866
Income taxes (a) (b) (c)	**809**	**832**	399	412	478	500
Earnings before cumulative effect of change in accounting principle	**2,003**	**2,046**	1,006	1,031	1,370	1,366
Cumulative effect of change in accounting principle, net of tax (d)	**–**	**–**	–	–	–	9
Net earnings	**2,003**	**2,046**	1,006	1,031	1,370	1,375
Other comprehensive income (b) (i)	**–**	**6**	–	(56)	–	74
Comprehensive income	**$ 2,003**	**$ 2,052**	$ 1,006	$ 975	$ 1,370	$ 1,449

(1) 2004 and 2003 amounts as restated (notes 3 and 11).

The increases or decreases noted above refer to the following differences between U.S. GAAP and Canadian GAAP:

(a) Under Canadian GAAP the ceiling test is performed by comparing the carrying value of the cost centre based on the sum of the undiscounted cash flows expected from the cost centre's use and eventual disposition. If the carrying value is unrecoverable the cost centre is written down to its fair value using the expected present value approach of proved plus probable reserves using future prices. Under U.S. GAAP, companies using the full cost method of accounting for oil and gas producing activities perform a ceiling test on each cost centre using discounted estimated future net revenue from proved oil and gas reserves using a discount factor of 10 percent. Prices used in the U.S. GAAP ceiling tests performed for this reconciliation were those in effect at the applicable year-end. At December 31, 2001, the Company recognized a U.S. GAAP ceiling test write down of $334 million after tax. Depletion expense for U.S. GAAP is reduced by $62 million (2004 – $76 million; 2003 – $80 million), net of tax of $21 million (2004 – $27 million; 2003 – $30 million).

Under U.S. GAAP, prices used in the reserve determination were those in effect at the applicable year-end. For Canadian GAAP, forecast prices are used in the reserve determination. The different prices result in a lower reserve base for U.S. GAAP. Additional depletion of $39 million, net of taxes of $14 million was recorded under U.S. GAAP in December 2004. As of the first quarter of 2005 these reserves have become economical again and are included in the reserve base resulting in a reduction to depletion expense for U.S. GAAP of $4 million, net of tax of $2 million.

(b) The Company records all derivative instruments as assets and liabilities on the balance sheet based on their fair values as required under FAS 133, "Accounting for Derivative Instruments and Hedging Activities". At December 31, 2005, the Company recorded additional assets and liabilities for U.S. GAAP purposes of $7 million (2004 – $52 million; 2003 – $52 million) and $39 million (2004 – $93 million; 2003 – $172 million), respectively, for the fair values of derivative financial instruments. The Company also recorded a gain of less than $1 million, net of tax (2004 – loss of less than $1 million; 2003 – loss of $2 million), in revenue for U.S. GAAP purposes with respect to derivatives designated as fair value hedges relating to commodity price risk. In addition, the amount included in other comprehensive income was increased by $1 million net of tax (2004 – decreased by $51 million; 2003 – increased by $69 million), for changes in the fair values of the derivatives designated as hedges of cash flows relating to commodity price risk, foreign exchange risk and the transfer to income of amounts applicable to cash flows occurring in 2005. In 2004, the Company unwound its long-dated foreign exchange forwards. The unrealized gain of $5 million, net of tax was deferred in other comprehensive income and recognized in 2005 when the underlying transactions took place. In 2005 and 2003 the Company unwound interest rate swaps that were fair value hedges of debt for proceeds of $37 million and $44 million, respectively. Under Canadian GAAP, the proceeds received have been recorded to current and long-term liabilities and are being deferred

over the life of the debt. For U.S. GAAP purposes, the balance in the current and long-term liabilities has been reclassified to long-term debt consistent with fair value hedge treatment. In prior years, the gains net of tax (2003 – $1 million), on foreign currency derivatives and natural gas basis swaps that did not qualify for hedge accounting under FAS 133 were included in income for U.S. GAAP purposes.

(c) Under U.S. GAAP, natural gas purchase and sale contracts related to energy trading activities are recorded at fair value in accordance with Emerging Issues Task Force 02-03, "Issues Involved in Accounting for Derivative Contracts held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities". Under Canadian GAAP, the impact of energy trading contracts is recorded as they settle. Under U.S. GAAP, at December 31, 2005 the Company recorded additional assets and liabilities of $49 million (2004 – $4 million; 2003 – $7 million) and $48 million (2004 – $3 million; 2003 – $5 million), respectively, and included the resulting unrealized gain, net of tax of less than $1 million (2004 – loss of $1 million; 2003 – loss of $9 million), in earnings for the year. Under U.S. GAAP, gains and losses on energy trading contracts have been netted against sales and operating revenues.

(d) In 2003, the Company adopted FAS 143, "Accounting for Asset Retirement Obligations", which requires the fair value of a liability for an asset retirement obligation to be recorded in the period in which it is incurred and a corresponding increase in the carrying amount of the related tangible long-lived asset. The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and normal use of the asset. The liability is accreted at the end of each period through charges to accretion expense. The change was effective January 1, 2003, and the related cumulative effect of change in accounting principle to net earnings to December 31, 2002 was an increase of $20 million, net of tax of $11 million or $0.02 per share (diluted). Effective January 1, 2004, under Canadian GAAP the Company adopted CICA section 3110, "Asset Retirement Obligations", which is substantially the same as the recommendations in FAS 143. CICA section 3110 was adopted retroactively with restatement. The application of asset retirement obligations did not have a material impact on the Company's depletion, depreciation and amortization rate. There was no impact on the Company's cash flow as a result of adopting asset retirement obligations.

(e) On September 3, 2003, the Company modified the exercise price of all outstanding options. Under U.S. GAAP these options are required to be accounted for using variable accounting where the in-the-money portion of the vested stock options outstanding is adjusted through the statement of earnings as compensation expense over the remaining vesting period.

Effective January 1, 2004, under Canadian GAAP, the Company adopted fair value accounting for stock-based compensation retroactively without restatement, which is consistent with the recommendations in FAS 123, "Accounting for Stock-based Compensation – Transition and Disclosure". As a result, the compensation expense of $46 million for the year ended December 31, 2003 was reversed through earnings and a compensation expense of $44 million was recognized for the fair value of all stock options.

(f) As a result of the reorganization of the capital structure which occurred in 2000, the deficit of Husky Oil Limited of $160 million was eliminated. Elimination of the deficit would not be permitted under U.S. GAAP.

(g) Until 1997 the Company recorded interest waived on subordinated shareholders' loans and dividends waived on Class C shares as a reduction of ownership charges. Under U.S. GAAP, waived interest and dividends in those years would be recorded as interest on subordinated shareholders' loans and dividends on Class C shares and as capital contributions.

(h) Under U.S. GAAP, transportation costs are included in cost of sales. Effective January 1, 2004, for Canadian purposes, certain transportation costs that were previously netted against revenue are now being recorded as cost of sales on a prospective basis. Transportation costs for 2003 were $112 million.

(i) The Company amortizes the portion of the unrecognized gains or losses that exceed 10 percent of the greater of the projected benefit obligation or the market-related value of pension plan assets. The market-related value of pension plan assets is the fair value of the assets or a calculated value that recognizes changes in fair value over not more than five years. Under U.S. GAAP, an additional minimum liability is recognized if the unfunded accumulated benefit obligation exceeds the unfunded pension cost already recognized. If an additional minimum liability is recognized, an amount equal to the unrecognized prior service cost is recognized as an intangible asset and any excess is reported in other comprehensive income. At December 31, 2005, the additional minimum liability was increased by $6 million (2004 – decrease of $1 million; 2003 – increase of $6 million) with a decrease to other comprehensive income of $5 million (2004 – decrease of less than $1 million; 2003 – decrease of $5 million), net of tax.

Additional U.S. GAAP Disclosures

Corporate Acquisitions

As described in note 7, Corporate Acquisitions, the Company purchased all of the outstanding shares of Temple Exploration Inc. and Marathon Canada Limited. The Company also purchased the Western Canadian assets of Marathon International Petroleum Canada, Ltd. These transactions increased the reserve base and created cost efficiencies, increasing shareholder value.

Accounting for Derivative Instruments and Hedging Activities

Effective January 1, 2001, the Company adopted the provisions of FAS 133, which require that all derivatives be recognized as assets and liabilities on the balance sheet and measured at fair value. Gains or losses, including unrealized amounts, on derivatives that have not been designated as hedges are included in earnings as they arise.

For derivatives designated as fair value hedges, changes in the fair value are recognized in earnings together with equal or lesser amounts of changes in the fair value of the hedged item. No portion of the fair value of the derivatives related to time value has been excluded from the assessment of hedge effectiveness in these hedging relationships.

For derivatives designated as cash flow hedges, the portion of the changes in the fair value of the derivatives that are effective in hedging the changes in future cash flows are recognized in other comprehensive income until the hedged items are recognized in earnings. Any portion of the change in the fair value of the derivatives that is not effective in hedging the changes in future cash flows is included in earnings. No portion of the fair value of the derivatives related to time value has been excluded from the assessment of hedge effectiveness in these hedging relationships.

Stock Option Plan

FAS 123 establishes financial accounting and reporting standards for stock-based employee compensation plans as well as transactions in which an entity issues its equity instruments to acquire goods or services from non-employees. As permitted by FAS 123, Husky has elected to follow the intrinsic value method of accounting for stock-based compensation arrangements, as provided for in Accounting Principles Board ("APB") Opinion 25. Since all options were granted with exercise prices equal to the market price, no compensation expense has been charged to income at the time of the option grants. On September 3, 2003, the Company modified the exercise price of all outstanding options, resulting in the use of variable accounting for these modified stock options. The table below provides pro forma amounts prior to the application of variable accounting which required recognition of compensation expense on September 3, 2003. Effective January 1, 2004, the Company adopted CICA section 3870, which requires the Company to record a compensation expense over the vesting period of the options based on the fair value of the options granted. CICA section 3870 is consistent with the recommendations in FAS 123. Had compensation cost for Husky's stock options been determined based on the fair market value at the grant dates of the awards, and amortized on a straight-line basis over the vesting period, consistent with methodology prescribed by FAS 123, Husky's net earnings and earnings per share for the year ended December 31, 2003 would have been the pro forma amounts indicated below:

	2003	
	As Reported	Pro Forma
Net earnings under U.S. GAAP	$ 1,375	$ 1,407
Earnings per share		
Basic	$ 3.28	$ 3.35
Diluted	$ 3.26	$ 3.34

The fair values of all common share options granted were estimated on the date of grant using the Black-Scholes option-pricing model. The weighted average fair market value of options granted during 2003 and the assumptions used in their determination are the same as described in note 15.

In December 2004, the Financial Accounting Standards Board ("FASB") issued FAS 123(R), "Share-based Payment", which replaces FAS 123 and supersedes APB Opinion 25. FAS 123(R) requires compensation cost related to share-based payments be recognized in the financial statements and that the cost must be measured based on the fair value of the equity or liability instruments issued. Under FAS 123(R) all share-based payment plans must be valued using option-pricing models. For U.S. GAAP, the liability related to the options issued under the Company's tandem plan will be measured at fair value using an option pricing model. Under Canadian GAAP, the liability will be measured based on the intrinsic value of the option. Over the life of the option the amount of compensation expense recognized will differ under U.S. and Canadian GAAP, creating a temporary GAAP timing difference. At exercise or surrender of the option, the compensation expense to be recorded will be equal to the cash payment which will be identical under U.S. and Canadian GAAP and there will no longer be a GAAP difference. FAS 123(R) is effective for the first quarter of 2006.

Depletion, Depreciation and Amortization

Upstream depletion, depreciation and amortization per gross equivalent barrel is calculated by converting natural gas volumes to a barrel of oil equivalent ("boe") using the ratio of 6 mcf of natural gas to 1 barrel of crude oil (sulphur volumes have been excluded from the calculation). Depletion, depreciation and amortization per boe as calculated under U.S. GAAP for the years ended December 31 were as follows:

	2005	2004	2003
Depletion, depreciation and amortization per boe	**$ 9.38**	$ 8.76	$ 7.35

Accounting for Inventory Costs

In November 2004, the FASB issued FAS 151, which clarifies the accounting for abnormal amounts of idle facility expense, freight, handling costs and wasted material as they relate to inventory costing. FAS 151 requires these items to be recognized as current period expenses. Additionally, the allocation of fixed production overheads to the cost of inventory should be based on the normal capacity of the production facilities. FAS 151 is effective for inventory costs incurred during fiscal years beginning after June 15, 2005. The Company does not believe that the application of FAS 151 will have an impact on the financial statements.

Accounting for Exchanges of Nonmonetary Assets

In December 2004, the FASB issued FAS 153, which deals with the accounting for the exchanges of nonmonetary assets. FAS 153 is an amendment of APB Opinion 29. APB Opinion 29 requires that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged. FAS 153 amends APB Opinion 29 to eliminate the exception from using fair market value for nonmonetary exchanges of similar productive assets and introduces a broader exception for exchanges of nonmonetary assets that do not have commercial substance. FAS 153 is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The Company does not believe that the application of FAS 153 will have an impact on the financial statements.

Accounting Changes and Error Corrections

In May 2005, the FASB issued FAS 154, which deals with all voluntary changes in accounting principles and changes required by an accounting pronouncement if that pronouncement does not include specific transition provisions. FAS 154 replaces APB Opinion 20, "Accounting Changes" and FAS 3, "Reporting Accounting Changes in Interim Financial Statements". This Statement requires retrospective application of a change in accounting principle to prior periods' financial statements, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change, in which case the change in principle is applied as if it were adopted prospectively from the earliest date practicable. Corrections of an error require adjusting previously issued financial statements. FAS 154 is effective for accounting changes and correction of errors made in fiscal years beginning after December 15, 2005.

Supplemental Financial and Operating Information

Quarterly Financial and Operating Information

Segmented Operational Information

	2005				2004			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Upstream								
Daily production, before royalties								
Light crude oil & NGL *(mbbls/day)*	75.4	56.4	62.5	64.1	60.9	64.8	69.2	70.4
Medium crude oil *(mbbls/day)*	31.0	30.3	30.6	32.4	33.7	34.5	35.6	36.1
Heavy crude oil *(mbbls/day)*	109.5	103.3	100.9	110.4	113.8	108.8	107.4	105.6
	215.9	190.0	194.0	206.9	208.4	208.1	212.2	212.1
Natural gas *(mmcf/day)*	675.3	679.2	689.3	676.2	697.4	700.4	685.4	673.6
Total production *(mboe/day)*	328.5	303.2	308.9	319.6	324.6	324.8	326.4	324.4
Average sales prices								
Light crude oil & NGL *($/bbl)*	$ 63.20	$ 67.21	$ 59.51	$ 56.43	$ 51.48	$ 53.54	$ 47.41	$ 41.84
Medium crude oil *($/bbl)*	$ 43.60	$ 53.41	$ 40.45	$ 36.50	$ 35.06	$ 40.59	$ 35.98	$ 32.97
Heavy crude oil *($/bbl)*	$ 29.98	$ 44.17	$ 27.95	$ 22.53	$ 25.81	$ 34.92	$ 27.54	$ 26.38
Natural gas *($/mcf)*	$ 11.39	$ 7.86	$ 6.76	$ 6.07	$ 6.64	$ 5.92	$ 6.38	$ 6.05
Operating costs *($/boe)*	$ 8.90	$ 8.18	$ 7.74	$ 7.60	$ 7.50	$ 7.57	$ 7.17	$ 7.03
Operating netbacks (1)								
Light crude oil *($/boe)*	$ 48.30	$ 51.79	$ 47.20	$ 44.03	$ 36.47	$ 39.71	$ 35.33	$ 30.91
Medium crude oil *($/boe)*	$ 24.80	$ 32.00	$ 23.58	$ 19.48	$ 20.08	$ 22.32	$ 20.03	$ 17.80
Heavy crude oil *($/boe)*	$ 15.73	$ 28.06	$ 15.52	$ 11.27	$ 13.75	$ 20.76	$ 15.28	$ 14.35
Natural gas *($/mcfge)*	$ 7.76	$ 4.95	$ 4.30	$ 3.83	$ 4.29	$ 3.58	$ 3.98	$ 3.87
Total *($/boe)*	$ 34.14	$ 33.48	$ 26.24	$ 22.80	$ 22.85	$ 24.92	$ 23.05	$ 21.40
Net wells drilled (2)								
Exploration Oil	25	28	10	22	23	4	5	7
Gas	60	43	21	72	46	23	11	100
Dry	10	7	5	14	3	1	1	28
	95	78	36	108	72	28	17	135
Development Oil	167	147	58	61	131	188	85	95
Gas	150	136	44	221	148	204	113	275
Dry	16	8	5	10	5	14	10	24
	333	291	107	292	284	406	208	394
	428	369	143	400	356	434	225	529
Success ratio *(percent)*	94	96	93	94	98	97	95	90
Midstream								
Synthetic crude oil sales *(mbbls/day)*	62.2	43.9	60.1	63.9	52.5	60.1	44.1	58.2
Upgrading differential *($/bbl)*	$ 33.31	$ 23.53	$ 31.05	$ 32.09	$ 25.72	$ 15.26	$ 17.10	$ 13.80
Pipeline throughput *(mbbls/day)*	480	418	488	510	479	461	520	510
Refined Products								
Refined products sales volumes								
Light oil products *(million litres/day)*	9.0	9.3	8.8	8.3	8.1	8.8	8.5	8.4
Asphalt products *(mbbls/day)*	22.4	29.9	19.7	17.7	20.8	27.6	24.2	18.4
Refinery throughput								
Lloydminster refinery *(mbbls/day)*	27.4	25.9	21.6	27.1	26.1	23.8	26.7	24.8
Prince George refinery *(mbbls/day)*	9.7	9.6	9.5	10.0	8.6	9.2	10.4	10.9
Refinery utilization *(percent)*	106	101	89	106	99	94	106	102

(1) Operating netbacks are Husky's average prices less royalties and operating costs on a per unit basis.

(2) Western Canada.

Segmented Financial Information

($ millions)	Upstream Q4	Upstream Q3	Upstream Q2	Upstream Q1	Midstream Upgrading Q4	Midstream Upgrading Q3	Midstream Upgrading Q2	Midstream Upgrading Q1
2005								
Sales and operating revenues, net of royalties	$ 1,327	$ 1,176	$ 976	$ 888	$ 414	$ 328	$ 393	$ 353
Costs and expenses								
Operating, cost of sales, selling and general	299	262	249	240	291	283	249	195
Depletion, depreciation and amortization	313	280	278	273	6	6	4	5
Interest – net	–	–	–	–	–	–	–	–
Foreign exchange	–	–	–	–	–	–	–	–
	612	542	527	513	297	289	253	200
Earnings (loss) before income taxes	715	634	449	375	117	39	140	153
Current income taxes	46	47	69	53	3	4	(2)	11
Future income taxes	136	142	73	83	32	8	45	35
Net earnings (loss)	$ 533	$ 445	$ 307	$ 239	$ 82	$ 27	$ 97	$ 107
Capital employed	$ 8,697	$ 8,005	$ 7,878	$ 7,636	$ 510	$ 489	$ 490	$ 509
Capital expenditures (2)	$ 831	$ 701	$ 536	$ 662	$ 35	$ 38	$ 30	$ 17
Total assets (3)	$ 12,887	$ 11,920	$ 11,575	$ 11,286	$ 844	$ 806	$ 751	$ 714
2004 (4)								
Sales and operating revenues, net of royalties	$ 722	$ 817	$ 800	$ 781	$ 291	$ 308	$ 213	$ 246
Costs and expenses								
Operating, cost of sales, selling and general	247	255	240	225	222	268	182	212
Depletion, depreciation and amortization	283	278	262	254	5	5	4	5
Interest – net	–	–	–	–	–	–	–	–
Foreign exchange	–	–	–	–	–	–	–	–
	530	533	502	479	227	273	186	217
Earnings (loss) before income taxes	192	284	298	302	64	35	27	29
Current income taxes	89	59	29	34	–	–	–	–
Future income taxes	(9)	64	65	32	18	11	8	6
Net earnings (loss)	$ 112	$ 161	$ 204	$ 236	$ 46	$ 24	$ 19	$ 23
Capital employed	$ 7,621	$ 7,409	$ 7,056	$ 6,874	$ 480	$ 487	$ 484	$ 455
Capital expenditures (2)	$ 664	$ 509	$ 421	$ 563	$ 24	$ 12	$ 18	$ 8
Total assets (3)	$ 11,046	$ 10,718	$ 10,305	$ 10,197	$ 708	$ 698	$ 688	$ 653

(1) Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventories.

(2) Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.

(3) Includes goodwill on corporate acquisitions related to Upstream.

(4) Amounts as restated. Refer to notes 3 and 11 to the Consolidated Financial Statements.

Midstream				Refined Products				Corporate and Eliminations [(1)]				Total			
Infrastructure and Marketing															
Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
$ 2,512	$ 1,808	$ 1,611	$ 1,452	$ 632	$ 716	$ 560	$ 437	$ (1,678)	$ (1,434)	$ (1,190)	$ (1,036)	$ 3,207	$ 2,594	$ 2,350	$ 2,094
2,427	1,752	1,552	1,353	592	660	518	399	(1,681)	(1,363)	(1,118)	(983)	1,928	1,594	1,450	1,204
5	5	6	5	13	14	11	9	6	6	5	6	343	311	304	298
–	–	–	–	–	–	–	–	16	–	6	10	16	–	6	10
–	–	–	–	–	–	–	–	5	(63)	20	7	5	(63)	20	7
2,432	1,757	1,558	1,358	605	674	529	408	(1,654)	(1,420)	(1,087)	(960)	2,292	1,842	1,780	1,519
80	51	53	94	27	42	31	29	(24)	(14)	(103)	(76)	915	752	570	575
–	(3)	(4)	(7)	–	(1)	(1)	(1)	28	31	13	11	77	78	75	67
27	20	24	39	10	16	12	12	(36)	(68)	(53)	(45)	169	118	101	124
$ 53	$ 34	$ 33	$ 62	$ 17	$ 27	$ 20	$ 18	$ (16)	$ 23	$ (63)	$ (42)	$ 669	$ 556	$ 394	$ 384
$ 359	$ 670	$ 570	$ 602	$ 475	$ 402	$ 399	$ 372	$ (635)	$ (290)	$ (234)	$ (211)	$ 9,406	$ 9,276	$ 9,103	$ 8,908
$ 13	$ 11	$ 7	$ 6	$ 86	$ 57	$ 43	$ 5	$ 7	$ 6	$ 4	$ 4	$ 972	$ 813	$ 620	$ 694
$ 866	$ 1,042	$ 871	$ 925	$ 834	$ 783	$ 727	$ 647	$ 366	$ 161	$ 134	$ 118	$15,797	$14,712	$14,058	$13,690
$ 1,455	$ 1,564	$ 1,669	$ 1,438	$ 465	$ 515	$ 457	$ 360	$ (915)	$ (1,013)	$ (929)	$ (804)	$ 2,018	$ 2,191	$ 2,210	$ 2,021
1,404	1,518	1,614	1,378	458	479	414	343	(890)	(988)	(886)	(779)	1,441	1,532	1,564	1,379
5	6	5	5	11	9	9	9	(2)	8	8	10	302	306	288	283
–	–	–	–	–	–	–	–	13	13	17	17	13	13	17	17
–	–	–	–	–	–	–	–	(60)	(84)	12	12	(60)	(84)	12	12
1,409	1,524	1,619	1,383	469	488	423	352	(939)	(1,051)	(849)	(740)	1,696	1,767	1,881	1,691
46	40	50	55	(4)	27	34	8	24	38	(80)	(64)	322	424	329	330
–	5	14	12	–	4	5	2	13	13	11	12	102	81	59	60
15	9	2	6	(1)	5	8	1	(28)	(43)	(42)	(30)	(5)	46	41	15
$ 31	$ 26	$ 34	$ 37	$ (3)	$ 18	$ 21	$ 5	$ 39	$ 68	$ (49)	$ (46)	$ 225	$ 297	$ 229	$ 255
$ 402	$ 390	$ 415	$ 342	$ 354	$ 372	$ 356	$ 297	$ (505)	$ (262)	$ (77)	$ (103)	$ 8,352	$ 8,396	$ 8,234	$ 7,865
$ 19	$ 5	$ 4	$ 3	$ 53	$ 29	$ 14	$ 10	$ 4	$ 8	$ 6	$ 5	$ 764	$ 563	$ 463	$ 589
$ 746	$ 718	$ 737	$ 765	$ 625	$ 647	$ 617	$ 578	$ 115	$ 120	$ 195	$ 124	$13,240	$12,901	$12,542	$12,317

Segmented Financial Information

($ millions)	2005 Q4	2005 Q3	2005 Q2	2005 Q1	2004 Q4	2004 Q3	2004 Q2	2004 Q1
Capital Expenditures (1)								
Upstream								
Western Canada	$ 648	$ 451	$ 376	$ 532	$ 433	$ 351	$ 270	$ 479
East Coast Canada and Frontier	151	230	140	124	167	152	138	82
International	32	20	20	6	64	6	13	2
	831	701	536	662	664	509	421	563
Midstream								
Upgrader	35	38	30	17	24	12	18	8
Infrastructure and marketing	13	11	7	6	19	5	4	3
	48	49	37	23	43	17	22	11
Refined Products	86	57	43	5	53	29	14	10
Corporate	7	6	4	4	4	8	6	5
	$ 972	$ 813	$ 620	$ 694	$ 764	$ 563	$ 463	$ 589

(1) Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.

Five-year Financial and Operating Information

Segmented Financial Information

	Upstream					Midstream									
						Upgrading					Infrastructure and Marketing				
($ millions)	2005	2004	2003	2002	2001	2005	2004	2003	2002	2001	2005	2004	2003	2002	2001
Year ended December 31 (2)															
Sales and operating revenues, net of royalties	$ 4,367	$ 3,120	$3,186	$2,665	$2,165	$1,488	$ 1,058	$ 1,013	$ 909	$ 886	$7,383	$ 6,126	$ 4,946	$ 4,230	$ 4,380
Costs and expenses															
Operating, cost of sales, selling and general	1,050	967	873	743	662	1,018	884	901	811	638	7,084	5,914	4,747	4,038	4,193
Depletion, depreciation and amortization	1,144	1,077	918	822	702	21	19	20	18	17	21	21	21	20	17
Interest – net	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Foreign exchange	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	2,194	2,044	1,791	1,565	1,364	1,039	903	921	829	655	7,105	5,935	4,768	4,058	4,210
Earnings (loss) before income taxes	2,173	1,076	1,395	1,100	801	449	155	92	80	231	278	191	178	172	170
Current income taxes	215	211	95	55	17	16	–	1	1	1	(14)	31	27	6	1
Future income taxes	434	152	233	346	293	120	43	20	25	72	110	32	37	59	71
Net earnings (loss)	$ 1,524	$ 713	$1,067	$ 699	$ 491	$ 313	$ 112	$ 71	$ 54	$ 158	$ 182	$ 128	$ 114	$ 107	$ 98
Capital employed – As at December 31	$ 8,697	$ 7,621	$6,607	$6,100	$5,763	$ 510	$ 480	$ 456	$ 319	$ 320	$ 359	$ 402	$ 450	$ 429	$ 393
Total assets – As at December 31 (3)	$12,887	$11,046	$9,847	$8,272	$7,443	$ 844	$ 708	$ 650	$ 659	$ 645	$ 866	$ 746	$ 804	$ 851	$ 863

(1) Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventories.

(2) 2004 and prior years' amounts as restated. Refer to notes 3 and 11 to the Consolidated Financial Statements.

(3) Includes goodwill on corporate acquisitions related to Upstream.

Segmented Financial Information

($ millions)	2005	2004	2003	2002	2001
Capital Expenditures [(1)]					
Upstream					
Western Canada	**$ 2,007**	$ 1,533	$ 1,195	$ 1,043	$ 1,023
East Coast Canada and Frontier	**645**	539	557	458	191
International	**78**	85	26	75	104
	2,730	2,157	1,778	1,576	1,318
Midstream					
Upgrader	**120**	62	25	41	47
Infrastructure and marketing	**37**	31	18	23	58
	157	93	43	64	105
Refined Products	**191**	106	58	44	29
Corporate	**21**	23	23	23	22
	$ 3,099	$ 2,379	$ 1,902	$ 1,707	$ 1,474

(1) Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.

Segmented Financial Information (continued)

	Refined Products					Corporate and Eliminations [(1)]					Total				
($ millions)	2005	2004	2003	2002	2001	2005	2004	2003	2002	2001	2005	2004	2003	2002	2001
Year ended December 31 [(2)]															
Sales and operating revenues, net of royalties	**$2,345**	$1,797	$1,502	$1,310	$1,349	**$(5,338)**	$(3,661)	$(2,989)	$(2,730)	$(2,184)	**$10,245**	$ 8,440	$ 7,658	$ 6,384	$ 6,596
Costs and expenses															
Operating, cost of sales, selling and general	**2,169**	1,694	1,426	1,224	1,208	**(5,145)**	(3,543)	(2,978)	(2,695)	(2,165)	**6,176**	5,916	4,969	4,121	4,536
Depletion, depreciation and amortization	**47**	38	26	31	27	**23**	24	36	17	15	**1,256**	1,179	1,021	908	778
Interest – net	**–**	–	–	–	–	**32**	60	102	136	133	**32**	60	102	136	133
Foreign exchange	**–**	–	–	–	–	**(31)**	(120)	(282)	10	115	**(31)**	(120)	(282)	10	115
	2,216	1,732	1,452	1,255	1,235	**(5,121)**	(3,579)	(3,122)	(2,532)	(1,902)	**7,433**	7,035	5,810	5,175	5,562
Earnings (loss) before income taxes	**129**	65	50	55	114	**(217)**	(82)	133	(198)	(282)	**2,812**	1,405	1,848	1,209	1,034
Current income taxes	**(3)**	11	9	4	1	**83**	49	15	–	–	**297**	302	147	66	20
Future income taxes	**50**	13	9	18	48	**(202)**	(143)	32	(101)	(99)	**512**	97	331	347	385
Net earnings (loss)	**$ 82**	$ 41	$ 32	$ 33	$ 65	**$ (98)**	$ 12	$ 86	$ (97)	$ (183)	**$ 2,003**	$ 1,006	$ 1,370	$ 796	$ 629
Capital employed – As at December 31	**$ 475**	$ 354	$ 315	$ 316	$ 307	**$ (635)**	$ (505)	$ (155)	$ 348	$ (114)	**$ 9,406**	$ 8,352	$ 7,673	$ 7,512	$ 6,669
Total assets – As at December 31 [(3)]	**$ 834**	$ 625	$ 540	$ 537	$ 431	**$ 366**	$ 115	$ 108	$ 317	$ 34	**$15,797**	$13,240	$11,949	$10,636	$ 9,416

Upstream Operating Information

	2005	2004	2003	2002	2001
Daily production, before royalties					
Light crude oil & NGL *(mbbls/day)*	**64.6**	66.2	71.6	65.4	46.4
Medium crude oil *(mbbls/day)*	**31.1**	35.0	39.2	44.8	47.2
Heavy crude oil *(mbbls/day)*	**106.0**	108.9	99.9	95.1	83.8
	201.7	210.1	210.7	205.3	177.4
Natural gas *(mmcf/day)*	**680.0**	689.2	610.6	569.2	572.6
Total production *(mboe/day)*	**315.0**	325.0	312.5	300.2	272.8
Average sales prices					
Light crude oil & NGL *($/bbl)*	**$ 61.56**	$ 48.34	$ 39.53	$ 36.17	$ 33.15
Medium crude oil *($/bbl)*	**$ 43.44**	$ 36.13	$ 31.42	$ 30.16	$ 23.69
Heavy crude oil *($/bbl)*	**$ 31.09**	$ 28.66	$ 25.87	$ 26.60	$ 17.02
Natural gas *($/mcf)*	**$ 7.96**	$ 6.25	$ 5.86	$ 3.83	$ 5.47
Operating costs *($/boe)*	**$ 8.12**	$ 7.32	$ 6.92	$ 6.24	$ 6.08
Operating netbacks (1)					
Light crude oil *($/boe)*	**$ 47.76**	$ 35.42	$ 30.21	$ 25.64	$ 20.37
Medium crude oil *($/boe)*	**$ 24.93**	$ 20.03	$ 16.76	$ 17.14	$ 12.29
Heavy crude oil *($/boe)*	**$ 17.57**	$ 16.02	$ 14.13	$ 15.85	$ 7.87
Natural gas *($/mcfge)*	**$ 5.22**	$ 3.92	$ 3.71	$ 2.46	$ 3.51

(1) Operating netbacks are Husky's average prices less royalties and operating costs on a per unit basis.

Upstream Operating Information

		2005		2004		2003		2002		2001	
		Gross	**Net**	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Wells drilled (1) (2) (3)											
Exploration	Oil	**89**	**85**	45	39	12	11	21	20	78	76
	Gas	**392**	**196**	234	180	147	124	139	131	102	90
	Dry	**36**	**36**	34	33	22	21	15	14	36	34
		517	**317**	313	252	181	156	175	165	216	200
Development	Oil	**466**	**433**	552	499	520	490	497	453	594	542
	Gas	**610**	**551**	807	740	540	518	485	453	251	221
	Dry	**42**	**39**	57	53	60	57	58	55	68	63
		1,118	**1,023**	1,416	1,292	1,120	1,065	1,040	961	913	826
		1,635	**1,340**	1,729	1,544	1,301	1,221	1,215	1,126	1,129	1,026
Success ratio *(percent)*		**95**	**94**	95	94	94	94	94	94	91	91

(1) Western Canada.

(2) Includes non-operated wells.

(3) Excludes stratigraphic test wells.

Selected Ten-year Financial and Operating Summary

($ millions, except where indicated)	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
Financial Highlights (1)										
Sales and operating revenues,										
net of royalties	**$ 10,245**	$ 8,440	$ 7,658	$ 6,384	$ 6,596	$ 5,066	$ 2,787	$ 2,023	$ 2,282	$ 2,104
Net earnings (loss)	**$ 2,003**	$ 1,006	$ 1,370	$ 796	$ 629	$ 398	$ 91	$ (8)	$ 55	$ 50
Earnings per share										
Basic	**$ 4.72**	$ 2.37	$ 3.26	$ 1.91	$ 1.51	$ 1.24	$ 0.34	$ (0.03)	$ 0.20	$ 0.18
Diluted	**$ 4.72**	$ 2.37	$ 3.25	$ 1.90	$ 1.50	$ 1.24	$ 0.34	$ (0.03)	$ 0.20	$ 0.18
Capital expenditures (2)	**$ 3,099**	$ 2,379	$ 1,902	$ 1,707	$ 1,474	$ 803	$ 706	$ 829	$ 601	$ 218
Total debt	**$ 1,886**	$ 2,152	$ 2,060	$ 2,740	$ 2,551	$ 2,716	$ 1,707	$ 1,475	$ 1,014	$ 853
Debt to capital employed *(percent)*	**20**	26	27	36	38	43	51	51	43	42
Reinvestment ratio (3) *(percent)*	**80**	110	91	78	79	59	142	204	132	46
Return on average capital										
employed (4) *(percent)*	**22.8**	13.0	18.9	12.3	10.8	11.9	7.3	4.3	7.2	6.7
Return on equity (5) *(percent)*	**29.2**	17.0	26.4	17.9	16.3	20.5	13.7	7.2	12.2	11.8
Upstream										
Daily production, before royalties										
Light crude oil & NGL *(mbbls/day)*	**64.6**	66.2	71.6	65.4	46.4	42.8	22.3	23.7	23.6	24.2
Medium crude oil *(mbbls/day)*	**31.1**	35.0	39.2	44.8	47.2	20.8	4.2	3.9	4.0	4.1
Heavy crude oil *(mbbls/day)*	**106.0**	108.9	99.9	95.1	83.8	53.5	42.1	42.0	41.9	34.5
	201.7	210.1	210.7	205.3	177.4	117.1	68.6	69.6	69.5	62.8
Natural gas *(mmcf/day)*	**680**	689	611	569	573	358	251	233	246	268
Total production *(mboe/day)*	**315.0**	325.0	312.5	300.2	272.8	176.8	110.4	108.4	110.6	107.5
Total proved reserves,										
before royalties *(mmboe)*	**985**	791	887	918	927	872	430	431	421	432
Midstream										
Synthetic crude oil sales *(mbbls/day)*	**57.5**	53.7	63.6	59.3	59.5	60.6	61.9	54.8	27.5	26.8
Upgrading differential *($/bbl)*	**$ 30.70**	$ 17.79	$ 12.88	$ 10.81	$ 17.91	$ 13.77	$ 6.49	$ 7.85	$ 8.54	$ 5.94
Pipeline throughput *(mbbls/day)*	**474**	492	484	457	537	528	394	412	417	359
Refined Products										
Light oil products sales *(million litres/day)*	**8.9**	8.4	8.2	7.7	7.6	7.4	7.6	6.0	4.5	4.2
Asphalt products sales *(mbbls/day)*	**22.5**	22.8	22.0	20.8	21.4	20.2	17.1	19.5	17.7	15.1
Refinery throughput										
Prince George refinery *(mbbls/day)*	**9.7**	9.8	10.3	10.1	10.2	9.2	10.2	9.9	10.3	10.0
Lloydminster refinery *(mbbls/day)*	**25.5**	25.3	25.7	22.0	23.7	23.4	17.9	21.9	21.5	18.4
Refinery utilization *(percent)*	**101**	100	103	92	97	93	80	91	91	81

(1) 2004 and prior years' amounts as restated. Refer to notes 3 and 11 to the Consolidated Financial Statements.

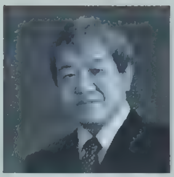
(2) Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.

(3) Reinvestment ratio is based on net capital expenditures including corporate acquisitions (other than Renaissance Energy Ltd.).

(4) Capital employed for purposes of this calculation has been weighted for 2000.

(5) Equity for purposes of this calculation has been weighted for 2000 and includes amounts due to shareholders prior to August 25, 2000.

Victor T. K. Li



Canning K. N. Fok

Board of Directors

Victor T. K. Li, Co-Chairman,
a resident of Hong Kong, has been a Director of Husky Energy Inc. since 2000. Mr. Li is Managing Director and Deputy Chairman of Cheung Kong (Holdings) Limited. He is Deputy Chairman and Executive Director of Hutchison Whampoa Limited, Chairman of Cheung Kong Infrastructure Holdings Limited, and of CK Life Sciences Int'l., (Holdings) Inc. Mr. Li is an Executive Director of Hongkong Electric Holdings Limited and a Director of the Hongkong and Shanghai Banking Corporation Limited.

Canning K. N. Fok (2), Co-Chairman,
a resident of Hong Kong, has been a Director of Husky Energy Inc. since 2000. Mr. Fok is Group Managing Director and Executive Director of Hutchison Whampoa Limited. He is Chairman of Hutchison Harbour Ring Limited, Hutchison Telecommunications International Limited, Hutchison Telecommunications (Australia) Limited, Partner Communications Company Ltd. and Hongkong Electric Holdings Limited. Mr. Fok is the Deputy Chairman of Cheung Kong Infrastructure Holdings Limited and a Director of Cheung Kong (Holdings) Limited and Hutchison Whampoa Finance (CI) Limited.

R. Donald Fullerton (1), Director,
a resident of Toronto, has been a Director of Husky Energy Inc. since 2003. Throughout his career he has sat on a wide variety of national and multinational boards and has served on the boards of many educational, medical and cultural institutions. He currently serves on the Board of Asia Satellite Communications Holdings Ltd. and 3Italia S.p.A.

Martin J. G. Glynn (1), Director,
a resident of New York, has been a Director of Husky Energy Inc. since 2000. Mr. Glynn is the President, Chief Executive Officer and a Director of HSBC Bank USA N.A. He is a Director of HSBC Bank Canada and of Wells Fargo HSBC Trade Bank N.A.

Terence C. Y. Hui (1), Director,
a resident of Vancouver, has been a Director of Husky Energy Inc. since 2000. Mr. Hui is President & Chief Executive Officer of Concord Pacific Group Inc. He is a Director and President of Adex Securities Inc. and a Director and Chairman of Maximizer Software Inc., Multiactive Technologies Inc., and Coopers Park Real Estate Corporation.

R. Donald Fullerton

Martin J. G. Glynn

Terence C. Y. Hui

Brent D. Kinney

Holger Kluge

Eva L. Kwok

Stanley T. L. Kwok

John C. S. Lau

Poh Chan Koh

Wayne E. Shaw

Frank J. Sixt

William Shurniak

Brent D. Kinney (3), Director,
a resident of Dubai, United Arab Emirates, has been a Director of Husky Energy Inc. since 2000. Mr. Kinney is Chief Executive Officer and a Director of Sky Petroleum Inc. and a Director of Dragon Oil plc, Western Silver Corp. and Benchmark Energy Ltd.

Holger Kluge (2) (3) (4), Director,
a resident of Toronto, has been a Director of Husky Energy Inc. since 2000. Mr. Kluge is a Director of Hutchison Whampoa Limited, Hongkong Electric Holdings Limited, and Shoppers Drug Mart.

Eva L. Kwok (2) (4), Director,
a resident of Vancouver, has been a Director of Husky Energy Inc. since 2000. Mrs. Kwok is a Director, Chairman and Chief Executive Officer of Amara International Investment Corp. She is a Director of the Bank of Montreal Group of Companies, CK Life Sciences Int'l., (Holdings) Inc., Li Ka Shing (Canada) Foundation, Cheung Kong Infrastructure Holdings Limited and Shoppers Drug Mart.

Stanley T. L. Kwok (3), Director,
a resident of Vancouver, has been a Director of Husky Energy Inc. since 2000. Mr. Kwok is the President of Stanley Kwok Consultants. He is a Director of Amara International Investment Corp., Cheung Kong (Holdings) Limited and CTC Bank of Canada.

John C. S. Lau, President & CEO, Director,
a resident of Calgary, has been a Director of Husky Energy Inc. since 2000. Prior to joining Husky in 1992, Mr. Lau served in a number of senior executive roles within the Cheung Kong (Holdings) Limited and Hutchison Whampoa Limited group of companies.

Poh Chan Koh, Director,
a resident of Hong Kong, has been a Director of Husky Energy Inc. since 2000. Miss Koh is the Finance Director of Harbour Plaza Hotel Management (International) Ltd.

Wayne E. Shaw (1) (4), Director,
a resident of Toronto, has been a Director of Husky Energy Inc. since 2000. Mr. Shaw is a Senior Partner at Stikeman Elliott LLP, Barristers & Solicitors.

Frank J. Sixt (2), Director,
a resident of Hong Kong, has been a Director of Husky Energy Inc. since 2000. Mr. Sixt is Group Finance Director and Executive Director of Hutchison Whampoa Limited. He is the Chairman of TOM Group Limited, an Executive Director of Cheung Kong Infrastructure Holdings Limited and Hongkong Electric Holdings Limited, and a Director of Cheung Kong (Holdings) Limited, Hutchison Whampoa Finance (CI) Limited, Hutchison Telecommunications (Australia) Limited and Partner Communications Company Ltd.

William Shurniak, Deputy Chairman,
a resident of Limerick, Saskatchewan, has been a Director of Husky Energy Inc. since 2000. Mr. Shurniak is Chairman and a Director of Northern Gas Networks Limited, and a Director of Hutchison Whampoa Limited.

The Management Information Circular and the Annual Information Form contain additional information regarding the Directors.

(1) Audit Committee
(2) Compensation Committee
(3) Health, Safety & Environment Committee
(4) Corporate Governance Committee

Corporate Information

Officers/Executives

John C. S. Lau

Robert J. Peabody

Donald R. Ingram

James D. Girgulis

HUSKY ENERGY INC.

John C. S. Lau, President & CEO
Mr. Lau is responsible for Husky's corporate direction, strategic planning and corporate policies, and is also a member of the Company's Board of Directors. Before joining Husky he served in a number of senior executive roles within the Cheung Kong (Holdings) Limited and Hutchison Whampoa Limited group of companies. Mr. Lau is a fellow member of the Institute of Chartered Accountants, the Australian Society of Accountants, the Hong Kong Society of Accountants, the Taxation Institute of Hong Kong, and the Institute of Chartered Secretaries of Administrators of the United Kingdom.

James D. Girgulis, Q.C., Vice President, Legal & Corporate Secretary
Mr. Girgulis was appointed Vice President, Legal & Corporate Secretary of Husky Energy in 2000. He was previously General Counsel and Corporate Secretary of Husky Oil Limited. Prior to joining Husky he held positions with Alberta and Southern Gas Co. and Alberta Natural Gas Company. Mr. Girgulis was called to the Alberta Bar in 1982 and was appointed Queen's Counsel in 2006.

Donald R. Ingram, Senior Vice President, Midstream & Refined Products
Mr. Ingram has been an officer of Husky since 1994. He joined the Company in 1982 and has over 30 years in the midstream and downstream business. Mr. Ingram is a Certified Management Accountant (CMA) and is a Fellow of the Society of Management Accountants of Canada (FCMA).

HUSKY OIL OPERATIONS LIMITED

Robert J. Peabody, Chief Operating Officer, Operations & Refining
Mr. Peabody was appointed Chief Operating Officer, Operations & Refining in 2006. He is responsible for managing Husky Energy's upstream operations including Western Canada conventional production, heavy oil, exploration and production services, east coast operations, frontier and international exploration and development, and refining and upgrading. Prior to joining Husky he led four major businesses for British Petroleum in Europe and the United States.

L. Geoffrey Barlow, Vice President & Controller
Mr. Barlow was Controller prior to his appointment as Vice President & Controller. He was previously Controller and a member of the management team at Renaissance Energy. He is a Chartered Accountant and is a member of the Institute of Chartered Accountants of Alberta and the Financial Executive Institute of Canada.

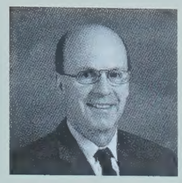
K. Wendell Carroll, Vice President, Corporate Administration
Mr. Carroll joined Husky in 2000 and brings with him 30 years of experience as a former senior manager with TransCanada Pipelines, Fracmaster and Bow Valley Industries. He is responsible for human resources, health, safety and environment, risk management, diversity, materials and services management, and facilities and records management and real estate.

Edward T. Connolly, Vice President, Heavy Oil
Edward T. Connolly joined Husky as Vice President of Heavy Oil in 2006 and has responsibility for increasing both heavy oil reserves and production while controlling costs. Mr. Connolly was previously Manager, Drilling, Well Completions and Facilities Construction with Talisman Energy Canada and Facilities Construction Project Manager with BP Canada Ltd.

Robert S. Coward, Vice President, Western Canadian Conventional Production
Mr. Coward became a corporate officer in 1993 and has served with Husky since 1977. He was appointed Vice President, Western Canada Conventional Production in 2005 and is responsible for optimizing the value of Husky's assets by increasing both reserves and production, and by controlling costs. Mr. Coward is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

J. Michael D'Aguiar, Treasurer
Mr. D'Aguiar joined Husky as Treasurer in 2002, and is responsible for the treasury department and associated financial functions. He has extensive financial experience in the international upstream oil industry. Prior to joining Husky he was Chief Financial Officer of Ranger Oil.

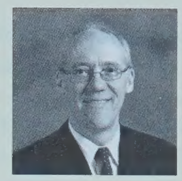
L. Geoffrey Barlow



K. Wendell Carroll

Edward T. Connolly

Robert S. Coward



J. Michael D'Aguiar

Steve P. F. Fedyna

Catherine J. Hughes

Garry P. Mihaichuk

David R. Taylor

Roy C. Warnock

Bill Watson

Ruud B. Zoon

Steve P.F. Fedyna, Vice President & Chief Information Officer
Mr. Fedyna is responsible for Husky's information technology, document management, corporate planning and economics, and investor relations and corporate communications. Appointed in 2005, he was formerly Director, Global Sales Operations with SAP Ag. He spent 17 years in project management, corporate planning, gas marketing and operations with Imperial Oil and Exxon Mobil Exploration. He is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

Catherine J. Hughes, Vice President, Exploration & Production Services
Ms. Hughes was appointed Vice President, Exploration & Production Services in 2005, and is responsible for the strategies and execution plans for surface land, mineral land, drilling and completions, facilities engineering and technical services, reservoir engineering and reserves. Prior to her appointment she was President of Schlumberger Canada, and has worked in a variety of operational and technical positions in the United States, United Kingdom, Europe and Nigeria.

Garry P. Mihaichuk, Vice President, Oil Sands
Mr. Mihaichuk became Vice President, Oil Sands in 2006, and is responsible for creating value from Husky's oil sands leases. Previously he was Vice President, Heavy Oil. He brings with him over 30 years of experience in executive positions in the energy, petrochemical and infrastructure sectors, and has served with Mancal Corporation, TransCanada, TransCanada Transmission, Amoco Corporation, Amoco Orient and Dome Petroleum.

David R. Taylor, Vice President, Exploration
Mr. Taylor has responsibility for capitalizing on Husky's assets in Western Canada and offshore Canada's East Coast, China and Indonesia. He was previously Vice President of Exploration for Renaissance Energy, and held senior technical and executive positions at Renaissance, Chauvco Resources, Imperial Oil and Exxon. Mr. Taylor is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, the Canadian Society of Petroleum Geologists and the American Association of Petroleum Geologists.

Roy C. Warnock, Vice President, Upgrading & Refining
Mr. Warnock has more than 25 years of experience in oil refining and upgrading, and joined Husky in 1983. He served as the Manager of Husky's Prince George refinery and the Lloydminster upgrader, before his appointment as Vice President, Upgrading & Refining. Prior to joining Husky, he held a number of engineering and operations positions with Imperial Oil. He is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, and the Association of Professional Engineers and Geoscientists of Saskatchewan.

Bill Watson, Vice President, Engineering & Project Management
Mr. Watson was appointed Vice President, Engineering & Project Management in 2004, and brings more than 30 years of experience in the energy business to Husky. Previously he was Vice President of Triton Equatorial Guinea Inc., a wholly owned subsidiary of Amerada Hess, and held management and executive positions with Marathon Oil Company including President of Marathon Canada Ltd.

Ruud B. Zoon, Vice President, East Coast Operations
Mr. Zoon joined Husky Energy in 2004 as General Manager, East Coast Development, and was appointed to his current position in 2005. Based in St. John's, he is responsible for all aspects of Husky's East Coast operations including the White Rose development. Prior to joining Husky he worked in leadership roles in the Netherlands, the United Kingdom, South Africa, China and the United States. He has worked for Sonoil B.V., Bluewater Energy Services B.V. and Mobil Oil Corporation. Mr. Zoon has been a member of the Society of Petroleum Engineers since 1984.

Investor Information

Common Share Information

Year ended December 31		2005	2004	2003
Share price	High	$ 69.95	$ 35.65	$ 23.95
	Low	$ 32.30	$ 22.73	$ 16.03
	Close at December 31	$ 59.00	$ 34.25	$ 23.47
Average daily trading volumes *(thousands)*		664	482	400
Number of common shares outstanding, December 31 *(thousands)*		424,125	423,736	422,176
Number of weighted average common shares outstanding *(thousands)*				
	Basic	423,964	423,362	419,543
	Diluted	423,964	424,303	421,549

Trading in the common shares of Husky Energy Inc. ("HSE") commenced on the Toronto Stock Exchange on August 28, 2000. The Company is represented in the S&P/TSX Composite, S&P/TSX Canadian Energy Sector and in the S&P/TSX 60 indices.

Toronto Stock Exchange Listing: HSE

Outstanding Shares
The number of common shares outstanding (in thousands) at December 31, 2005 was 424,125.

Transfer Agent and Registrar
Husky's transfer agent and registrar is Computershare Trust Company of Canada. In the United States, the transfer agent and registrar is Computershare Trust Company, Inc. Share certificates may be transferred at Computershare's principal offices in Calgary, Toronto, Montreal and Vancouver, and at Computershare's principal office in Denver, Colorado, in the United States.

Queries regarding share certificates, dividends and estate transfers should be directed to Computershare Trust Company at 1-888-267-6555 (toll free in North America).

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www.huskyenergy.ca
Terra Nova website:
www.terranovaproject.com
Wenchang website:
www.huskywenchang.com
White Rose website:
www.huskywhiterose.com

Auditors
KPMG LLP
1200, 205 Fifth Avenue S.W.
Calgary, Alberta
T2P 4B9

Annual and Special Meeting
The annual and special meeting of shareholders will be held at 10:30 a.m. on Wednesday, April 19, 2006 in the Palomino Ballroom, at the Round Up Centre, Stampede Park, Thirteenth Avenue and Third Street S.E., Calgary, Alberta.

Additional Publications
The following publications are made available on our website or from our Investor Relations department:

- Annual Information Form, filed with Canadian securities regulators
- Form 40-F, filed with the U.S. Securities and Exchange Commission
- Quarterly Reports

Corporate Governance
For information regarding the Company's corporate governance practices, please see the Schedule A "Statement of Corporate Governance Practices" to our Management Information Circular. The Management Information Circular is available on our website, www.huskyenergy.ca.

Dividends
Husky's Board of Directors has approved a dividend policy that pays quarterly dividends.

Declaration Date	Quarter Dividend	Special Dividend
October 2005	$ 0.25	$ 1.00
July 2005	0.14	
April 2005	0.14	
February 2005	0.12	
November 2004	0.12	0.54
July 2004	0.12	
April 2004	0.12	
February 2004	0.10	
November 2003	0.10	
July 2003	0.10	1.00
April 2003	0.09	
February 2003	0.09	
November 2002	0.09	
August 2002	0.09	
May 2002	0.09	
February 2002	0.09	
November 2001	0.09	
August 2001	0.09	
May 2001	0.09	
February 2001	0.09	

Terms and Abbreviations

bbls	barrels
bps	basis points
mbbls	thousand barrels
mbbls/day	thousand barrels per day
mmbbls	million barrels
mcf	thousand cubic feet
mmcf	million cubic feet
mmcf/day	million cubic feet per day
bcf	billion cubic feet
tcf	trillion cubic feet
boe	barrels of oil equivalent
mboe	thousand barrels of oil equivalent
mboe/day	thousand barrels of oil equivalent per day
mmboe	million barrels of oil equivalent
mcfge	thousand cubic feet of gas equivalent
GJ	gigajoule
mmbtu	million British Thermal Units
mmlt	million long tons
MW	megawatt
MWh	megawatt hour
NGL	natural gas liquids
WTI	West Texas Intermediate
NYMEX	New York Mercantile Exchange
NIT	NOVA Inventory Transfer (1)
LIBOR	London Interbank Offered Rate
CDOR	Certificate of Deposit Offered Rate
SEDAR	System for Electronic Document Analysis and Retrieval
FPSO	Floating production, storage and offloading vessel
OPEC	Organization of Petroleum Exporting Countries
WCSB	Western Canada Sedimentary Basin
SAGD	Steam-assisted gravity drainage
hectare	1 hectare is equal to 2.47 acres
wildcat well	Exploratory well drilled in an area where no production exists
feedstock	Raw materials which are processed into petroleum products

(1) NOVA Inventory Transfer is an exchange or transfer of title of gas that has been received into the NOVA pipeline system but not delivered to a connecting pipeline.

Natural gas converted on the basis that six mcf of natural gas equals one barrel of oil.

Capital Employed	Short- and long-term debt and shareholders' equity
Capital Expenditures	Includes capitalized administrative expenses and capitalized interest but does not include proceeds or other assets
Cash Flow from Operations	Earnings from operations plus non-cash charges before settlement of asset retirement obligations and change in non-cash working capital
Equity	Shares, retained earnings and amounts due to shareholders prior to August 25, 2000
Net Debt	Total debt net of cash and cash equivalents
Total Debt	Long-term debt including current portion and bank operating loans

"Proved" reserves have been estimated in accordance with the SEC definition set out in Rule 4-10(a) of Regulation S-X under the Securities Exchange Act of 1934 as follows: Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

"Proved Developed" reserves are those reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

"Proved Undeveloped" reserves are those reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells for which a relatively major expenditure is required for recompletion. Inclusion of reserves on undrilled acreage is limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are included only if it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

"Probable" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved and probable reserves.

In this report, the terms "Husky Energy Inc.", "Husky" or "the Company" mean Husky Energy Inc. and its subsidiaries and partnership interests on a consolidated basis.

This Annual Report contains certain forward-looking statements. For a description and discussion of these forward-looking statements and the risks and uncertainties related thereto, please refer to page 67 of this Annual Report and also to Husky's Annual Information Form dated March 14, 2006.

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